Federal Energy Administration
Project Independence Blueprint
Final
Task Force Report

Natural Gas

Project Independence

Under Direction of
Federal Power Commission
November 1974

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Prepared by the
Interagency Task Force on
Natural Gas

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J. 561-737

For sale by the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402
Stock Number 4118-00014

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FEDERAL ENERGY ADMINISTRATION

WASHINGTON, D.C. 20461

November 1974

This report contains the final technical analysis of the Project Independence Interagency Natural Gas Task Force chaired by the Federal Power Commission. The task force was formed in April 1974 to provide estimates for the Project Independence Blueprint of the potential production capabilities of the natural gas industry and the resources necessary to achieve these levels of production. The task force evaluated two alternative strategies. The first was "business-as-usual," which assumed the continuation of all current policies that could affect levels of natural gas production. The second strategy, "accelerated demand," assumed selected changes in policies or practices that would permit a greater expansion of potential production.

The data support from the Natural Gas Task Force, together with estimates of resource availability, conservation and demand forecasts served as input into the Project Independence Blueprint analysis. This report is not a production or price forecast and does not represent policy or program recommendations of the Federal Energy Administration or of the other participating agencies.

The cooperation given by all agencies involved in developing this report is greatly appreciated. The special contribution of the Task Force Chairman is gratefully acknowledged as well as the extensive support given by the staff of the Federal Power Commission.

SUMMARY

Background and Purpose of Study

Total proved reserves of natural gas in the U. S. reached a peak of 293 trillion cubic feet in 1967 and year-end reserves have declined since then in each year except in 1970, when the Prudhoe Bay field reserves were added to the inventory. Proved reserves amounted to 250 trillion cubic feet at year-end 1973, 218 trillion cubic feet of which were located in the lower 48 states. Historically, gas reserve additions exceeded production in each year until 1968. Since that time the reverse has been true except in 1970 (due to Prudhoe Bay additions). During this six-year period of decline, annual reserve additions have averaged only 9.5 trillion cubic feet for the lower 48 states, as opposed to average annual production of 21.4 trillion cubic feet. In order to maintain our current production level, it would be necessary to add new reserves of approximately 22.5 trillion cubic feet annually, a formidable task in light of the fact that since 1946 our average annual reserve additions have been slightly less than 16 trillion cubic feet (about 17 trillion including Alaska).

Total oil and gas well drilling reached a peak in this country in 1956, and has generally followed a downward trend since. Gas well drilling has, however, held rather steady and recently has exhibited an upward trend. While this trend reversal is encouraging, it is not clear that new field exploratory gas well drilling has also increased. Moreover, the amount of gas found per foot of new field exploratory drilling is apparently continuing on a downward trend.

The PIB Natural Gas Task Force was asked to project what could or might occur with respect to non-associated natural gas from domestic sources during the period 1974 through 1990. Two sets of assumptions were specified by the Blueprint management. These sets, labelled Business-As-Usual (BAU) and Accelerated Development (ACC), differ primarily in that no new government policies or actions were to be considered under BAU whereas new policies and actions could be formulated for the ACC scenario.

Project Independence Blueprint management specified the data required from the task force. Data in three general categories were required: production data, price and cost data, and resource input data. Estimated production was to be consistent with the basic assumptions of the relevant scenario and represent the upper limit of the range of production that could occur assuming no constraints on the total availability of capital, labor and materials. Cost data were to include and consider the costs associated with the acquisition, exploration, development and production of non-associated natural gas exclusive of lease bonuses and rentals. The recoupment of these investments and a realization of a 10 percent DCF rate of return were specified in order to arrive at a "minimum acceptable price" per unit of production. The resource inputs associated with the levels of production in the form of total capital investments, labor (delineated by certain standard categories), and materials (also identified by type) were also required.

Task Force Methodology and Assumptions

The Natural Gas Task Force would have preferred to develop its own stochastic model of the industry reflecting the uncertainty associated with exploration for gas. However, the short time frame within which the study had to be completed precluded this approach. As an alternative, the non-stochastic model developed by the National Petroleum Council in U. S. Energy Outlook, Oil and Gas Availability, 1973, was adopted in modified form. Modifications included developing a new section which calculated "minimum acceptable price" using a discounted cash flow technique, and extensive updating and revision of the data base through 1973 to reflect recent trends in critical variables. Some special sources of gas, specifically Alaska, gas from tight formations and gas occluded in coal seams, were not amenable to inclusion in the NPC program and were analyzed independently.

The approach adopted by the Task Force contains several recognized deficiencies relating to its theoretical basis, the specific formulation of the overall model, and the reliability of projections of many critical input variables. These were not correctable within the time available for the study and the results should be reviewed with this fact in mind.

Exhibit 1 contains a listing of general assumptions applicable to both scenarios and listing of assumptions which were scenario specific. In terms of analysis of the results, it is important to note that exclusion of lease bonuses and rentals results in somewhat

Exhibit 1

Natural Gas Scenario Assumptions

General

Rate of Return Required on Investment (DCF)	10.0%
Depletion Allowance	22.0%
Federal Income Tax Rate	48.0%
Lease Bonuses and Rentals	None

	Scenario Specific	
Item	Business as Usual	Accelerated Development
Drilling Rate	Task Force BAU Estimate	Task Force ACC Estimate
Finding Rate	Task Force Estimate	Task Force Estimate
Drilling Costs	Task Force Estimate	Task Force Estimate
Leasing	Task Force BAU Estimate	Task Force ACC Estimate
Royalties	One-sixth offshore, one-eighth onshore	One-eighth everywhere
Incentives	Current Regulatory Environment	Increased Price Incentives

lower "minimum acceptable prices" particularly in offshore areas. These costs were excluded in order to allow policy consideration of economic rents in the subsequent integrating effort.

The most critical variables used by the NPC were evaluated and revised by the Task Force. These included projections of the amount of gas found per foot of drilling, the level of drilling activity, real 1974 exploration, drilling and other costs, and depletion rates. Other less important variables were also reviewed and evaluated as enumerated in the detailed Task Force report.

Exhibit 2 sets forth the overall national drilling escalation factors used in each scenario. The BAU drilling escalation is the same as the "high" drilling schedule used in the NPC study while the ACC drilling escalation schedule reflects both a higher ultimate drilling rate and greater levels of drilling activity earlier in the period due to the impact of increased price incentives. Exhibits 3 and 4 indicate the distribution of the drilling effort scheduled in each year among the various NPC regions. These differ between scenarios primarily because of the more rapid and/or earlier opening of new frontier areas to exploration and development and the higher levels of drilling activity in the accelerated scenario. In the BAU Scenario, offshore leasing was projected at levels consistent with current published BLM schedules. In the Accelerated Scenario, OCS lands were assumed to be made available at annual rates that would not constrain offshore exploration and development. BAU offshore royalty rates were assumed to continue at their current level of 1/6 while in the ACC case royalties were assumed to be the statutory minimum of 1/8.

The Task Force developed its own finding curve for each region based upon an extrapolation of historical plots of cumulative gas findings versus cumulative gas drilling footage. Exhibits 5 and 6 detail the projections of reserves found per foot drilled in each region in each year. The same regional finding curve was used in both scenarios, but because the cumulative footages drilled differ at a given point in time, the amount found per foot also differs.

The current costs of exploration, drilling and production, including tax items, were reviewed and updated by the Task Force. The depletion schedules for both old and newly discovered reserves were also reviewed. After consideration those values in the previous NPC study were adopted without modification.

Exhibit 2

Annual Drilling Escalation Factors (Percent)
Gas Well Footage Plus Allocated Dry Holes
Initial Footage Drilled (1973) = 59,665,000

Year	Business As Usual	Accelerated Development
1974	0.00	0.00
1975	5.00	8.33
1976	5.50	15.38
1977	6.00	13.33
1978	6.50	11.76
1979	7.00	5.26
1980	7.50	5.00
1981	8.00	4.76
1982	8.50	4.54
1983	9.00	4.34
1984	7.00	4.17
1985	5.00	4.00
1986	3.00	3.85
1987	1.00	3.70
1988	0.00	3.57

Exhibit 3

Percentage Allocation of Drilling Activity By Region
Non-Associated Gas-Lower 48 States
Business as Usual

Region	Actual 1971	1972	1973	Projected 1974	1975	1976	1977	1978	1979	1980
2	1.2	1.1	1.1	1.2	1.3	1.5	1.6	1.7	1.8	1.8
2A	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2
3	7.7	5.0	5.2	5.0	5.0	5.0	5.0	5.0	5.1	5.1
4	5.5	5.2	4.3	4.4	4.7	4.8	5.4	5.6	5.6	5.7
5	9.2	8.8	11.6	10.0	10.1	10.2	10.2	10.2	10.2	10.2
6	37.1	38.2	36.2	38.9	38.1	37.4	36.5	36.1	34.8	34.5
6A	10.0	7.2	7.2	7.4	9.3	10.6	11.3	12.1	13.0	13.1
7	12.1	18.0	18.0	17.0	16.0	15.3	15.3	15.3	15.6	15.6
8&9	1.2	1.1	1.1	1.1	1.0	0.9	0.8	0.7	0.7	0.7
10	16.0	15.4	15.3	15.0	14.5	14.0	13.5	12.8	12.6	12.6
11	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.4
11A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

Region	Projected 1981	1982	1983	1984	1985	1986	1987	1988
2	1.9	2.0	2.0	1.8	1.7	1.7	1.7	1.7
2A	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
3	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
4	5.7	5.7	6.0	6.1	6.2	6.2	6.2	6.2
5	10.4	10.5	10.6	10.7	10.6	10.6	10.6	10.6
6	33.8	33.3	32.6	32.1	32.1	32.1	32.1	32.1
6A	13.3	13.5	13.2	12.5	12.5	12.5	12.5	12.5
7	15.6	15.6	15.6	15.7	15.8	15.8	15.8	15.8
8&9	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
10	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
11	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
11A	0.2	0.3	0.9	2.0	2.0	2.0	2.0	2.0

Exhibit 4

Percentage Allocation of Drilling Activity by Region
Non-Associated Gas-Lower 48 States
Accelerated Development

Region	Actual 1971	1972	1973	Projected 1974	1975	1976	1977	1978	1979	1980
2	1.2	1.1	1.1	1.2	1.3	1.5	1.6	1.7	1.8	1.8
2A	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4
3	7.7	5.0	5.2	5.0	5.0	5.0	5.0	5.0	5.0	5.0
4	5.5	5.2	4.3	4.4	4.7	4.8	5.4	5.5	5.6	5.6
5	9.2	8.8	11.6	10.0	10.1	10.1	10.1	10.1	10.1	10.1
6	37.1	38.2	36.2	38.9	38.1	37.3	36.2	35.7	34.7	33.7
6A	10.0	7.2	7.2	7.4	9.3	10.6	11.5	12.5	13.5	14.0
7	12.1	18.0	18.0	17.0	16.0	15.3	15.3	15.2	15.2	15.2
8&9	1.2	1.1	1.1	1.1	1.0	0.9	0.8	0.7	0.7	0.7
10	16.0	15.4	15.3	15.0	14.5	14.0	13.5	12.7	12.2	12.3
11	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.4
11A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.8

Region	Projected 1981	1982	1983	1984	1985	1986	1987	1988
2	1.8	1.8	1.9	1.8	1.7	1.7	1.6	1.6
2A	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
3	5.0	4.9	4.9	4.9	4.9	4.8	4.8	4.7
4	5.6	5.5	5.7	5.8	5.9	5.9	5.9	5.9
5	10.1	10.1	10.1	10.2	10.1	10.0	9.9	9.9
6	32.8	32.1	31.1	30.6	30.4	30.3	30.2	30.1
6A	14.4	14.7	15.0	15.0	15.0	15.0	15.0	15.0
7	15.1	15.1	15.0	15.0	15.0	14.9	14.9	14.9
8&9	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
10	12.2	12.2	12.1	12.1	12.0	11.9	11.8	11.8
11	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
11A	1.3	1.9	2.5	2.9	3.3	3.8	4.2	4.4

Exhibit 5

Projected Non-Associated Gas Reserves Added Per Foot Drilled-Lower 48 States Business As Usual

	Regions							
Year	2	2A	3	4	5	6	6A	7
1974	140	--	117	155	330	172	850	170
1975	140	-	117	150	320	170	820	165
1976	140	750	117	145	310	168	780	160
1977	139	750	117	140	300	166	750	155
1978	139	750	117	135	290	163	715	150
1979	138	750	117	131	280	156	675	145
1980	138	750	117	127	270	149	640	141
1981	137	750	117	123	260	142	600	138
1982	137	750	117	119	250	135	555	135
1983	135	750	115	116	240	128	515	132
1984	135	750	115	113	230	120	475	129
1985	133	750	115	110	220	112	440	126
1986	133	750	115	107	210	104	400	124
1987	130	750	115	104	200	94	370	122
1988	130	750	115	101	190	84	340	120

	Regions			
Year	8&9	10	11	11A
1974	75	80	-	-
1975	72	80	-	-
1976	69	80	20	-
1977	66	79	20	-
1978	63	79	20	-
1979	60	78	20	-
1980	57	78	20	750
1981	54	76	20	750
1982	51	75	20	750
1983	48	74	20	750
1984	45	73	20	750
1985	42	72	20	750
1986	39	71	20	750
1987	36	70	20	750
1988	33	69	20	750

Note: All Volumes in Mcf/foot

Exhibit 6

Projected Non-Associated Gas Reserves Added
Per Foot Drilled--Lower 48 States
Accelerated Development

Year	Regions 2	2A	3	4	5	6	6A	7
1974	140	-	117	155	330	172	850	170
1975	140	-	117	150	320	170	795	165
1976	140	750	117	144	308	168	770	159
1977	139	750	117	139	297	165	735	153
1978	138	750	117	133	285	160	695	147
1979	138	750	117	129	273	152	650	142
1980	137	750	117	124	260	145	605	139
1981	137	750	117	119	250	137	555	136
1982	136	750	115	116	240	130	510	132
1983	135	750	115	113	230	120	460	129
1984	133	750	115	110	220	114	435	127
1985	133	750	115	107	210	106	380	125
1986	130	750	115	104	200	96	340	123
1987	129	750	115	102	190	85	295	121
1988	127	750	115	99	183	76	250	119

Year	Regions 8&9	10	11	11A
1974	75	80	-	-
1975	72	80	-	-
1976	69	80	20	-
1977	66	79	20	-
1978	63	79	20	750
1979	60	78	20	750
1980	57	76	20	750
1981	54	75	20	750
1982	51	74	20	750
1983	48	73	20	750
1984	45	72	20	750
1985	42	71	20	750
1986	39	70	20	750
1987	36	69	20	750
1988	33	68	20	750

Note: All Volumes in Mcf/foot

Due to the highly subjective nature of the modeling effort in terms of the assessment of critical inputs, several sensitivity runs were made to indicate the effects of significant, but not unreasonably large, deviations of the most critical input data from values used in the business as usual case. These runs serve to highlight the varying sensitivity of our results to a range of input values and should be carefully considered by users of these data.

Major Findings

Projections of Production Possibilities

The projections of production possibilities made by the Task Force hinge primarily on the projected success of the non-associated gas exploration effort. The non-associated additions to reserves are summarized by region in Exhibit 7 where it will be noted that in both the BAU and ACC scenarios total annual findings peak late in the projection period and then begin to decline. This reflects drilling of progressively poorer prospects, offsetting the increases in total drilling projected in both scenarios, and is indicative of the depletable character of a finite resource base. Given these finding data, the known reserves, and the depletion schedules, production possibilities were projected versus "minimum acceptable price" as indicated in Exhibit 8. Perhaps more illuminating is a restatement of this same data in Exhibit 9. Here the increments of production in each "minimum acceptable price" interval show that as time progresses the new found gas comes into production at somewhat higher "prices", reflecting increased costs due to the expansion of exploration and drilling efforts in the face of generally declining finding rates.

The most important sensitivity runs made by the Task Force embodied alternate assumptions for finding rates, rate of return on investment, and inclusion of lease bonus and rental costs. The finding rates were uniformly increased and decreased by 20%, resulting in new discovery volumes differing from the BAU base by that amount. Corresponding regional "minimum acceptable prices" were approximately 16 to 20% less in the increased case and 24 to 28% higher in the decreased case, illustrating considerable price sensitivity to finding rate. The rate of return was set at 15% and 7.5%, resulting in "price" increases of 28 to 33% in the former case and "price" decreases of 13 to 18% in the latter.

Exhibit 7

Summary of Non-Associated Reserve Addition Projections
and their "Minimum Acceptable Prices"
Lower 48 States 1/

NPC Region		1974 Reserve Additions	1974 "Price"	1977 Reserve Additions	1977 "Price"	1980 Reserve Additions	1980 "Price"	1985 Reserve Additions	1985 "Price"	1988 Reserve Additions	1988 "Price"
2	BAU 2/	0.100	$0.60	0.156	$0.65	0.213	$0.66	0.278	$0.69	0.283	$0.71
	ACC 3/	0.100	0.60	0.188	0.64	0.258	0.66	0.292	0.69	0.293	0.72
2A	BAU	0.0	--	0.105	0.69	0.129	0.71	0.277	0.80	0.288	0.86
	ACC	0.0	--	0.253	0.66	0.313	0.68	0.582	0.76	0.649	0.82
3	BAU	0.349	0.79	0.410	0.78	0.512	0.80	0.722	0.83	0.751	0.84
	ACC	0.349	0.79	0.494	0.78	0.611	0.80	0.728	0.83	0.780	0.84
4	BAU	0.407	0.35	0.530	0.48	0.621	0.51	0.840	0.58	0.802	0.62
	ACC	0.407	0.35	0.634	0.49	0.725	0.53	0.816	0.59	0.843	0.63
5	BAU	1.969	0.31	2.144	0.47	2.364	0.58	2.872	0.63	2.580	0.75
	ACC	1.969	0.31	2.534	0.48	2.772	0.60	2.742	0.67	2.614	0.77
6	BAU	3.992	0.43	4.245	0.54	4.412	0.61	4.428	0.86	3.455	1.20
	ACC	3.992	0.43	5.046	0.54	5.103	0.64	4.166	0.91	3.301	1.34
6A	BAU	3.753	0.29	5.938	0.35	7.195	0.44	6.774	0.71	5.445	0.96
	ACC	3.753	0.27	7.141	0.34	8.846	0.45	7.368	0.79	5.411	1.28
7	BAU	1.724	0.47	1.661	0.55	1.888	0.61	2.452	0.69	2.429	0.73
	ACC	1.724	0.47	1.978	0.56	2.206	0.62	2.424	0.70	2.559	0.74
8 & 9	BAU	0.049	0.77	0.037	1.04	0.034	1.23	0.036	1.81	0.030	2.42
	ACC	0.049	0.77	0.045	1.04	0.042	1.23	0.038	1.81	0.033	2.42
10	BAU	0.716	0.78	0.747	0.70	0.843	0.70	1.117	0.80	1.114	0.84
	ACC	0.716	0.78	0.901	0.70	0.976	0.73	1.101	0.81	1.158	0.85
11	BAU	0.0	--	0.003	5.78	0.007	5.80	0.010	5.79	0.010	5.79
	ACC	0.0	--	0.003	5.78	0.008	5.80	0.010	5.79	0.012	5.79
11A	BAU	0.0	--	0.0	--	0.064	0.89	1.847	0.92	1.922	0.95
	ACC	0.0	--	0.0	--	0.627	0.85	3.199	0.88	4.762	0.90
Sum of Additions:											
	BAU	13.059		15.976		18.282		21.653		19.109	
	ACC	13.059		19.217		22.487		23.466		22.415	

1/ Volumes in trillions of cubic feet, "prices" in cents per Mcf (constant 1973 dollars).
2/ Business as Usual Scenario.
3/ Accelerated Development Scenario.

Exhibit 8

Total Non-Associated Gas Production Possibilities
Lower 48 States 1/

1974		1977		1980		1985		1988		"Minimum Acceptable Price"
BAU 2/	ACC 3/	BAU	ACC	BAU	ACC	BAU	ACC	BAU	ACC	of Last Mcf
16.522	16.522	13.132	13.133	9.683	9.683	5.509	5.509	3.812	3.812	$0.20
16.522	16.522	14.215	14.250	11.793	12.109	6.993	7.219	4.830	4.986	0.30
16.522	16.552	15.222	15.284	13.187	13.652	9.163	9.100	6.630	6.529	0.40
16.550	16.550	15.667	15.767	15.470	16.013	13.388	12.867	9.867	9.465	0.50
16.550	16.550	15.697	15.804	15.653	16.711	15.865	17.030	13.139	13.781	0.60
16.550	16.550	15.919	16.035	16.011	17.023	17.193	18.548	16.099	16.475	0.70
16.550	16.550	15.923	16.040	16.014	17.026	17.349	19.114	17.227	17.866	0.80
16.550	16.550	15.925	16.042	16.012	17.030	17.361	19.116	17.829	18.858	0.90
16.550	16.550	15.925	16.042	16.019	17.033	17.362	19.118	18.011	19.513	1.00
16.550	16.550	15.925	16.042	16.024	17.039	17.366	19.122	18.014	19.683	1.10
16.550	16.550	15.925	16.042	16.025	17.040	17.382	19.141	18.037	19.709	2.00 or more

1/ Volumes in trillions of cubic feet, "prices" in cents per Mcf (constant 1973 dollars).
2/ Business as Usual Scenario.
3/ Accelerated Development Scenario.

Exhibit 9
Increments of Non-Associated Gas Production for Selected "Minimum Acceptable Price" Intervals 1/
Lower 48 States
(Derived from Exhibit 8)

"Price" Interval	1974 BAU 2/	1974 ACC 3/	1977 BAU	1977 ACC	1980 BAU	1980 ACC	1985 BAU	1985 ACC	1988 BAU	1988 ACC
0-20¢	16.552	16.552	13.132	13.132	9.683	9.683	5.509	5.509	3.812	3.812
20-30	0.0	0.0	1.083	1.117	2.110	2.426	1.484	1.710	1.018	1.174
30-40	0.0	0.0	1.007	1.034	1.394	1.543	2.170	1.881	1.800	1.543
40-50	0.028	0.028	0.445	0.483	2.283	2.361	4.225	3.767	3.237	2.936
50-60	0.0	0.0	0.030	0.037	0.183	0.698	2.477	4.163	3.272	4.316
60-70	0.0	0.0	0.222	0.231	0.358	0.312	1.328	1.518	2.960	2.694
70-80	0.0	0.0	0.004	0.005	0.003	0.003	0.156	0.566	1.128	1.391
80-90	0.0	0.0	0.002	0.002	0.003	0.004	0.012	0.002	0.602	0.992
90-100	0.0	0.0	0.0	0.0	0.002	0.003	0.001	0.002	0.182	0.655
100-110	0.0	0.0	0.0	0.0	0.005	0.006	0.004	0.004	0.003	0.170
110-120	0.0	0.0	0.0	0.0	0.0	0.0	0.002	0.003	0.001	0.002
120-130	0.0	0.0	0.0	0.0	0.0	0.0	0.003	0.003	0.002	0.002
130-140	0.0	0.0	0.0	0.0	0.0	0.0	0.002	0.003	0.002	0.003
140-150	0.0	0.0	0.0	0.0	0.0	0.0	0.004	0.003	0.003	0.002
150-160	0.0	0.0	0.0	0.0	0.0	0.0	0.003	0.002	0.002	0.003
160-170	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
170-180	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.003	0.003
180-190	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.003	0.003
190 or higher	0.0	0.0	0.0	0.0	0.001	0.001	0.004	0.005	0.007	0.008
Sum of Increments:	16.55	16.55	15.925	16.042	16.025	17.040	17.382	19.141	18.037	19.709
Weighted Average Prices 4/										
For All Gas	20.08	20.08	22.70	22.82	27.00	27.87	37.50	39.81	46.57	49.58
For Production From Projected Discoveries	Nil Production	Nil Production	35.47	35.56	37.68	44.24	45.62	47.82	53.69	56.68

1/ "Prices" in cents per Mcf, volumes in Tcf.
2/ Business As Usual Scenario.
3/ Accelerated Development Scenario.
4/ Volumes weighted by mid-point "prices" of the intervals.

Inclusion of lease bonus and rental costs increased "prices" by about 10% in onshore areas and by varied amounts in offshore areas ranging from 36% to 265%, depending on the year and area. Taken together, these results indicate a high degree of sensitivity of "minimum acceptable price" to a number of factors, both natural and policy determined.

Exhibit 10 shows the associated-dissolved gas production possibilities projected by the Oil Task Force as a co-product of its oil production projections, arrayed versus oil "price".

With respect to the special sources, Exhibits 11 and 12 indicate the projected production levels and prices which were manually derived by the Task Force. Gas from Alaska, relatively inexpensive at the lease, will be elevated dramatically in price by inclusion of transportation costs to the lower 48 states. The projections of production of gas from tight formations are contingent upon successful development of technology for its recovery. The amounts of gas recoverable from coal seams will be negligible.

Capital, Materials and Labor Requirements

Based upon its projections of industry activity and production, the Task Force estimated the amounts of capital, materials and labor required. The most accurate of these derived values was for capital and the least accurate was for labor. Projections were made in each region for each year of the requirements for 21 possibly critical raw, semi-finished or fabricated material goods, the number of exploratory crew-months and the number of drilling rig personnel man-years, and for labor requirements in total and broken out by 74 occupational skill categories. The materials and labor data, too voluminous to summarize here in a meaningful way, will be considered by the integrating effort to determine possible constraints on production.

The capital required to support the projected activity is large. Exhibit 13 indicates the possible capital requirements arising from the exploration for, and production of non-associated gas in the lower 48 states outlined in Exhibit 8. These capital requirement projections will be analyzed intensively in the integrating effort in view of possible financing constraints.

Exhibit 10

Associated-Dissolved Natural Gas Production Production Projections
Lower 48 States and Alaskan Region 1S

Scenario	YEAR 1974	1977	1980	1985	1988	Minimum Acceptable Oil "Price"
Business As Usual	3.665	3.167	2.871	2.649	2.484	$ 4.00
	3.665	3.365	3.159	3.018	2.941	7.00
	3.665	3.079	3.084	3.827	3.994	11.00
Accelerated Development	3.665	3.327	3.128	3.083	3.000	4.00
	3.665	3.533	3.580	3.679	3.685	7.00
	3.665	3.539	3.709	4.415	4.761	11.00

Note: Production given in Tcf; Minimum Acceptable Price given in constant 1973 dollars per barrel.

Exhibit 11

Alaskan Production Projections

Type of Gas/ Region/Scenario/ Activity Level	1974		1977		1980		1985		1988	
	Production	Price *	Production	Price *	Production	Price *	Production	Price *	Production	Price *
Non-Associated										
Region 1N										
BAU/Low	0.0	--	0.0	--	0.094	0.42	0.160	0.42	0.184	0.42
BAU/Medium	0.0	--	0.0	--	0.150	0.40	0.320	0.40	0.410	0.40
BAU/High	0.0	--	0.0	--	0.180	0.43	0.415	0.43	0.540	0.43
ACC/Low	0.0	--	0.0	--	0.225	0.81	0.485	0.81	0.615	0.81
ACC/Medium	0.0	--	0.0	--	0.270	0.53	0.630	0.53	0.814	0.53
ACC/High	0.0	--	0.0	--	0.295	0.53	0.690	0.53	0.895	0.53
Region 1S										
BAU/Low	0.120	0.30	0.135	0.30	0.155	0.30	0.310	0.30	0.352	0.30
BAU/Medium	0.120	0.47	0.150	0.47	0.225	0.47	0.470	0.47	0.630	0.47
BAU/High	0.120	0.56	0.150	0.56	0.225	0.56	0.560	0.56	0.792	0.56
ACC/Low	0.120	0.47	0.200	0.47	0.430	0.47	0.800	0.47	1.050	0.47
ACC/Medium	0.120	0.49	0.225	0.49	0.500	0.49	1.000	0.49	1.360	0.49
ACC/High	0.120	0.51	0.275	0.51	0.515	0.51	1.125	0.51	1.530	0.51
Associated-Dissolved										
Region 1N										
Prudhoe Bay, BAU, All Cases	0.0	--	0.0	--	0.675	2.24	1.350	2.24	1.350	2.24
Prudhoe Bay, ACC, Low	0.0	--	0.0	--	0.675	2.24	1.350	2.24	1.350	2.24
Prudhoe Bay, ACC, Medium and High	0.0	--	0.0	--	0.675	2.03	2.107	2.03	2.350	2.03
NPR 4/Low	0.0	--	0.0	--	0.0	6.02	0.885	6.02	1.270	6.02
NPR 4/High	0.0	--	0.0	--	0.0	9.03	0.885	9.03	2.381	9.03
Other Areas	0.0	--	0.0	--	0.169	5.89	0.571	5.89	0.548	5.89

Region 1S - Included in Exhibit 10.

* Price given is gas price for non-associated production and oil price for associated-dissolved production.

Note: Production given in Tcf, "Minimum Acceptable Price" given in constant 1973 dollars per Mcf or per barrel; BAU = Business As Usual. ACC = Accelerated Devlopment. AD price projections for Region 1N are not yet updated, and will be included in the final report.

Exhibit 12

Projected Production of Gas from Special Sources

Source/Region/Scenario/ Activity Level		1974		1977		1980		1985		1990	
		Production	Price	Production	Price	Production	Price	Production	Price	Production	Price
Tight Reservoirs/											
Region 3/	BAU/Low	0.0	--	0.0	--	0.0	--	0.0	--	0.0	--
	BAU/Medium	0.0	--	0.0	--	0.0	--	0.0	--	0.0	--
	BAU/High	0.0	--	0.0	--	0.1	0.34	0.2	0.40	0.3	0.46
	ACC/Low	0.0	--	0.0	--	0.1	0.46	0.3	0.54	0.5	0.58
	ACC/Medium	0.0	--	0.0	--	0.2	0.48	0.3	0.56	0.5	0.61
	ACC/High	0.0	--	0.0	0.29	0.8	0.32	1.5	0.38	1.7	0.42
Region 4/	BAU/All Levels	0.0	--	0.0	--	0.0	--	0.0	--	0.0	--
	ACC/Low	0.0	--	0.0	--	0.0	--	0.0	--	0.0	--
	ACC/Medium	0.0	--	0.0	--	0.1	0.48	0.3	0.56	0.3	0.61
	ACC/High	0.0	--	0.0	--	0.3	0.32	0.5	0.38	0.6	0.42
Occluded in Coal * /											
Region 6/	BAU	0.0	--	0.0003	--	0.0004	--	0.0006	--	0.0005	--
	ACC	0.0	--	0.0009	--	0.001	--	0.002	--	0.003	--
Region 9/	BAU	0.0	--	0.003	--	0.005	--	0.007	--	0.007	--
	ACC	0.0	--	0.010	--	0.016	--	0.025	--	0.036	--
Region 10/	BAU	0.0	--	0.003	--	0.005	--	0.006	--	0.006	--
	ACC	0.0	--	0.010	--	0.015	--	0.024	--	0.034	--

Note: Production given in Tcf, "Minimum Acceptable Price" given in constant 1973 dollars per Mcf; BAU = Business As Usual, ACC = Accelerated Development

* No activity levels, as this source is controlled by mining activity.

Exhibit 13

Non-Associated Gas Investment Requirements, Lower 48 States 1/
Business as Usual 2/

1974	1977	1980	1985	1988	"Minimum Acceptable Price" of Last Mcf
1288	314	0	0	0	20 or less
1647	446	445	0	0	30
1647	883	793	0	0	40
1652	883	1120	506	286	50
1688	1023	1284	1187	595	60
1769	1037	1284	1788	766	70
1769	1037	1303	1937	1529	80
1769	1037	1306	1937	1569	90
1769	1037	1306	1937	2024	100
1769	1037	1306	1937	2024	110
1769	1037	1306	1937	2024	120
1769	1037	1306	1942	2024	130
1769	1037	1306	1942	2024	140
1769	1037	1306	1942	2024	150
1769	1037	1306	1942	2024	160
1769	1037	1306	1942	2024	170
1769	1037	1306	1942	2029	180
1769	1037	1306	1942	2029	190
1769	1038	1309	1946	2034	200 or more

1/ Capital requirements in millions of constant 1973 dollars, "price" in cents per Mcf.
2/ Corresponds to volumes in Exhibits 8 and 9.

FINAL REPORT OF THE
INTERAGENCY TASK FORCE ON NATURAL GAS

I INTRODUCTION

Statement of Task Force Mission

The Natural Gas Task Force was established in the late spring of 1974 to assist the Federal Energy Office in formulating a blueprint for Project Independence. Other resource development task forces were also established and given parallel responsibilities in other energy sectors.

The assignment of the Natural Gas Task Force was to project alternative future levels of non-associated gas production and the capital, manpower and materials associated with these levels of resource development. These projections were to be generated under two alternative scenarios or cases--business as usual and accelerated development. The business as usual scenario assumes that present governmental policies will be continued and that no new governmental policies and actions will be undertaken in the future which would affect the rate of development of the natural gas resource base. The accelerated development case assumes that new governmental policies would be put into effect or present policies modified to relax or eliminate certain "constraints" on production. Projections of supply that could be available in the future were required on a regional basis for the years 1974, 1977, 1980, 1985 and 1988. The regions adopted for use were those previously established by the National Petroleum Council (NPC) and are illustrated in Figure I-1.

The assignment given to the task force was to approximate the price-supply-resource relationships that might or could exist under these alternative scenarios. It was not to predict natural gas production levels and/or prices which the task force members believed would actually be obtained as a result of the interactions of the various operative constraints to production. It is apparent, therefore, that the projections made in this report are not amenable to meaningful comparison with published forecasts of production.

Project Independence Blueprint management specified the data required from the task force. Data in three general categories were required: production data, price and cost data, and resource input data. Estimated production was to be consistent with the basic assumptions of the relevant scenario and represent the upper limit of the range of production that could occur assuming no constraints on the total availability of capital, labor and

NATIONAL PETROLEUM COUNCIL'S SUPPLY REGIONS

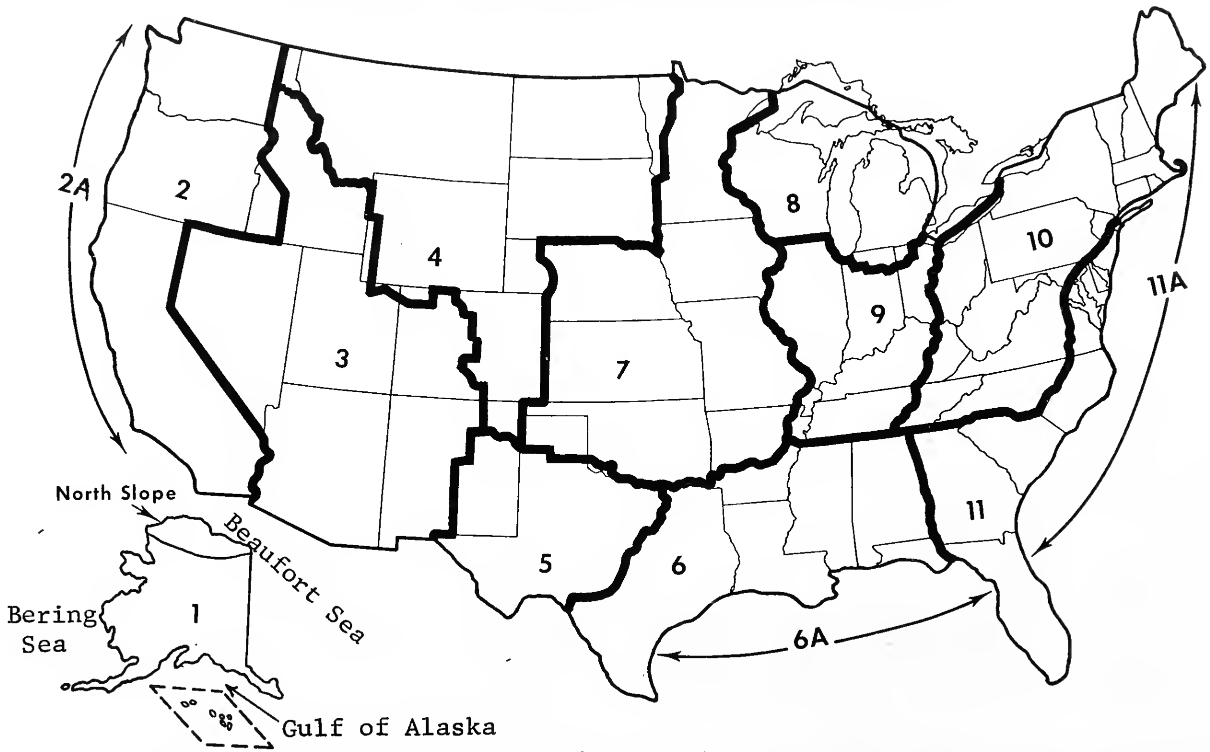


Figure I-1

Source: NPC Future Petroleum Provinces of the United States (July 1970).

materials. Cost data were to include and consider the costs associated with the acquisition, exploration, development and production of non-associated natural gas exclusive of lease bonuses and rentals. The recoupment of these investments and a realization of a 10 percent DCF rate of return were specified in order to arrive at a "minimum acceptable price" per unit of production. The resource inputs associated with the levels of production in the form of total capital investments, labor (delineated by certain standard categories), and materials (also identified by type) were also required.

It was recognized very early that a unique relationship existed between the efforts of the Oil Task Force and the Natural Gas Task Force. This relationship stemmed from the numerous physical, institutional and economic factors common to each. For instance common leases may be productive of oil and gas; the drilling rigs, manpower and equipment required for the development of both resources are essentially the same; the companies involved in the development of oil and gas are usually interested in either product and are usually in the business of developing and selling both; and oil production usually involves the production of associated-dissolved gas as a co-product while gas production usually involves the ancillary production of certain quantities of liquid hydrocarbons. Because of the many resource, economic and institutional factors common to both gas and oil, the Natural Gas Task Force and Oil Task Force worked very closely on those matters affecting both sectors.

It was decided by the gas and oil task forces that the approach and methodology developed by the NPC in its U.S. Energy Outlook, Oil and Gas Availability Study, 1973 would be reviewed and modified to the extent necessary in order to utilize the analytical and computational capability which had already been established. Numerous modifications were made to the NPC computer program before its use by the task forces. These included extensive updating and revision of input data and major changes in the economic section of the program to allow estimates of a "minimum acceptable price" on a discounted cash flow basis. The Natural Gas Task Force was substantially assisted in the updating and revision process by several consulting groups. Major contributions were made by consultants from the firms of ICF, Inc., Resource Planning and Associates and LaRue, Moore and Schafer. Personnel from other Federal agencies including the Department of the Interior, Federal Energy Administration and Environmental Protection Agency also contributed to the task force effort. An organization chart of the task force and a chart showing the task force relationship to the PIB organization are shown in Figures I-2 and I-3.

This report does not necessarily represent the position of the Federal Power Commission, other government agencies or individual participants insofar as the future levels and economics of natural gas production are concerned.

Study Limitations

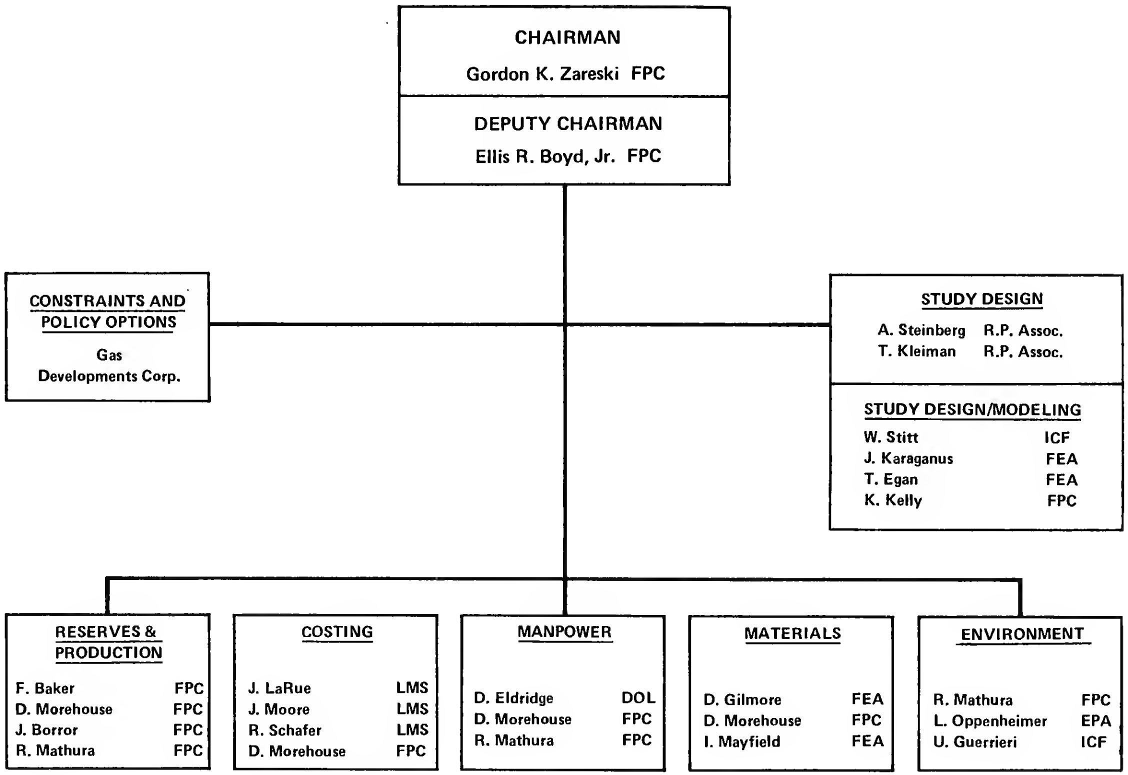
As stated above, the data presented here were developed expressly for use in the Project Independence Blueprint effort under assumptions specifically tailored to this purpose. Users of these data must therefore be cautious to utilize this information only in a manner which fully and completely recognizes the unique character and nature of these estimates.

In the sections that follow we attempt to detail for the reader exactly what we have done to arrive at these projections and provide extensive detail on the methodology utilized and on the many assumptions involved. An examination of this material could lead the reader to a misleading sense of precision with respect to these projections. While they represent our best judgment, they are the product of a myriad of assumptions, approximations, allocations, projections and judgments which, taken together, result in values of varying precision.

Perhaps the greatest caution needs to be exercised with respect to the "minimum acceptable prices" generated herein. While the relationship between the price offered for natural gas and the elicited supply has been a matter of intensive study by numerous economists over the past 15 years, it is generally conceded that there is no model or method which enables this relationship to be reliably predicted. A reliable determination of supply elasticity has not been possible because this determination depends on quantifying the effect of the many variables other than price which impinge on the rate at which gas may be found and developed. While values of "minimum acceptable price" computed under the guidelines established by Project Independence Management may provide useful information within the context of the PIB integrating model for the various energy forms, these

FIGURE I-2

NATURAL GAS TASK FORCE ORGANIZATION



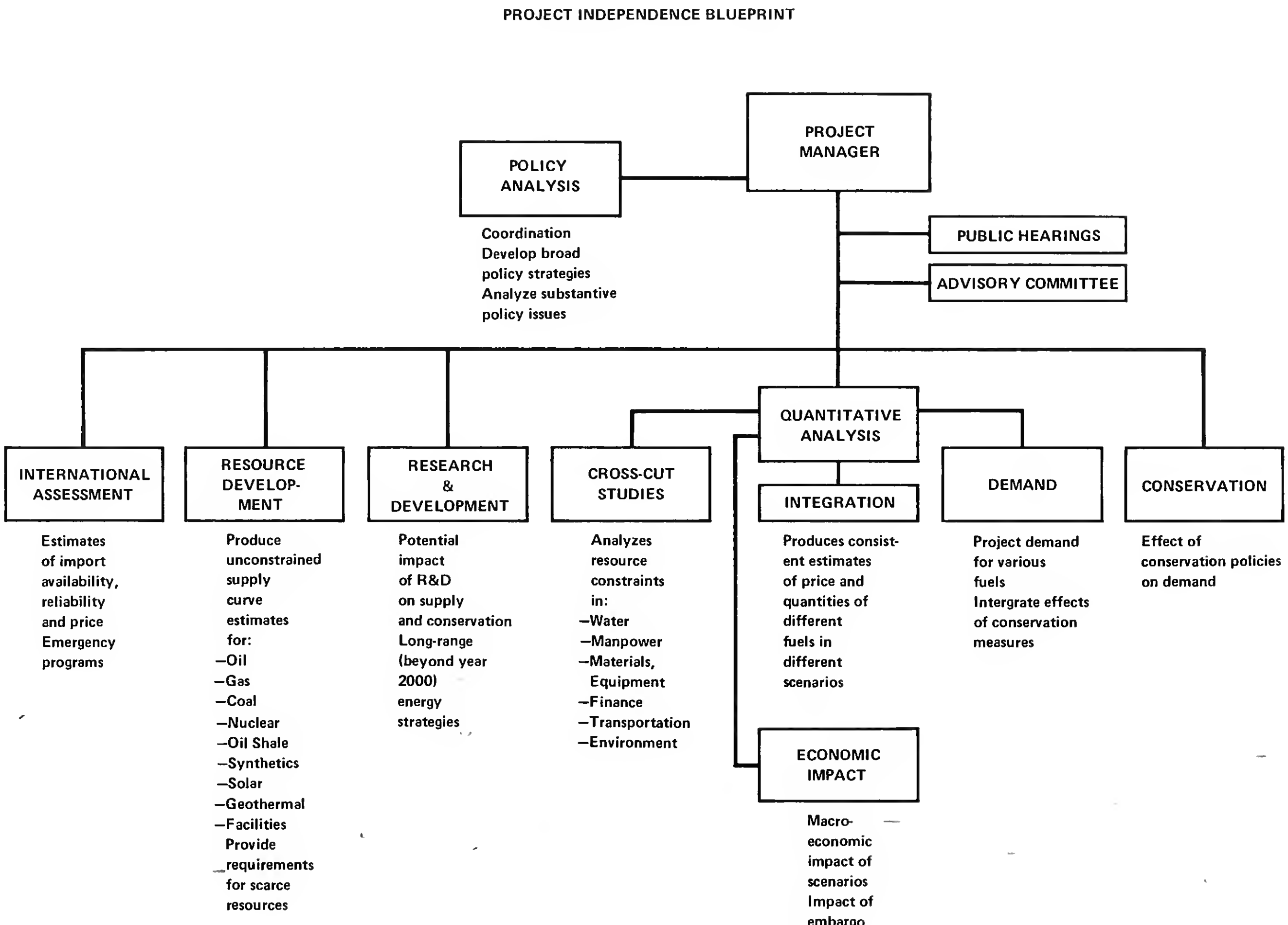

PROJECT INDEPENDENCE BLUEPRINT
PROJECT MANAGER
POLICY ANALYSIS
Coordination
Develop broad policy strategies
Analyze substantive policy issues
PUBLIC HEARINGS
ADVISORY COMMITTEE
INTERNATIONAL ASSESSMENT
Estimates of import availability, reliability and price
Emergency programs
RESOURCE DEVELOP-MENT
Produce unconstrained supply curve estimates for:
—Oil
—Gas
—Coal
—Nuclear
—Oil Shale
—Synthetics
—Solar
—Geothermal
—Facilities
Provide requirements for scarce resources
RESEARCH & DEVELOPMENT
Potential impact of R&D on supply and conservation
Long-range (beyond year 2000) energy strategies
CROSS-CUT STUDIES
Analyzes resource constraints in:
—Water
—Manpower
—Materials, Equipment
—Finance
—Transportation
—Environment
QUANTITATIVE ANALYSIS
INTEGRATION
Produces consistent estimates of price and quantities of different fuels in different scenarios
ECONOMIC IMPACT
Macro-economic impact of scenarios
Impact of embargo
DEMAND
Project demand for various fuels
Intergrate effects of conservation measures
CONSERVATION
Effect of conservation policies on demand

FIGURE I-3

values must not be construed as measures of supply-price elasticity. Indeed, if this relationship could be developed, producer price regulation would be greatly simplified.

It must also be recognized that the concept of a "minimum acceptable price," as computed herein, may be quite different than the actual interactions of price, return and resources encountered by real life producers. In our computations here, each effort on the part of a producer to develop non-associated gas resources is assumed to meet with success in a manner consistent with historical cost and finding trends in that particular area/region. In reality, the ability and experience of each producer is quite relevant to the success and cost experience which he in-fact encounters. The concept used here is non-probabilistic in that footage drilled is assumed to yield given quantities of gas at given costs and provide each operator with a specified return on his investment.

The methodology and assumptions utilized in our estimates are covered in detail in the sections which follow. As these factors are examined, it will become apparent that the projections of future supply and attendant resource requirements are quite sensitive to these inputs. This is due to the character of the estimates being made and the relationship of the relevant factors one to another.

Of particular importance is the gas finding rate anticipated in response to future footage drilled. To the extent that future findings deviate from the levels anticipated, significant error will result. If, for example, actual findings are 20 percent greater than anticipated, a given level of drilling activity would result in the development of 20 percent more gas. Thus, not only would a significantly greater amount of gas be developed, but, since the extractive costs would not rise proportionately, because of the high ratio of fixed to variable costs, the unit costs of the resource developed would be significantly reduced.

The deviation of future levels of drilling activity from the levels projected could also prove troublesome. Of course, the level of drilling activity will have a direct bearing on the amount of resource developed but beyond that are the distortions which would follow in the estimates of capital, manpower and materials required since these items are based on the number of feet and wells drilled.

Other inputs whose values can have a significant impact on the resulting estimates include the drilling and production costs related to the development of the resource and the rate of return attributed to these operations. Drilling costs have been particularly volatile in the recent past and to the extent that these costs and rates of return do not accurately reflect future experience, our estimates of capital required will be in error.

A number of computer runs were made for alternative levels of certain of the more critical input variables in order to indicate the sensitivity of the projections to a range of alternative assumptions. These analyses, which revealed considerable sensitivity to the selected values of some of the input variables, are important to understanding the results displayed herein and are presented in Section VI.

Present U.S. Natural Gas Supply Position

Proved Reserves

For many years this country had a surplus of natural gas. This condition resulted from the many gas fields discovered as a result of the search for oil and the large volumes of associated-dissolved gas found in conjunction with oil discoveries. Initially, local markets were unable to utilize all of the available gas supply. However, the rapid expansion of the long-distance interstate pipeline system after World War II, consumer preference for this environmentally superior fuel, and the recent downward trend of supply developed in relation to production withdrawn have combined to manifest themselves in the present natural gas shortage. Total U.S. gas supply trends with and without Alaska are shown in Tables I-1 and I-2.

Total proved reserves of natural gas in the U.S. reached a peak of 293 trillion cubic feet at the end of 1967. Until that time, natural gas reserve additions had exceeded production each year. However, in 1968 production exceeded reserve additions and this situation has continued except for 1970 when Alaska's Prudhoe Bay field reserves were added to the inventory. In the lower 48 states production has exceeded reserve additions in each of the past six years. During this period reserve additions in the contiguous states have averaged only 9.5 trillion cubic feet annually compared to annual average production of 21.4 trillion cubic feet. This imbalance between reserve additions and production has resulted in a sharp decline in proved reserves since 1967 and has accelerated the decline in the reserve to production (R/P) ratio. The R/P ratio which was 32.5 at the end of 1946 had declined to 11.1 and 9.7 by the end of 1973 for the total U.S. and the lower 48 states, respectively. Proved reserves with and without Alaska were 250 and 218 trillion cubic feet at the end of 1973.

Maintenance of our current level of production would require annual additions to our proved reserve inventory of approximately 22.5 trillion cubic feet. This will be a formidable task because, since 1946, average annual additions in the lower 48 states have been slightly less than 16

Table I-1
United States Natural Gas Supply
1918-1973
(Volumes in Trillion Cubic Feet)

Year (1)	Production (2)	Reserve Additions (3)	Proved Reserves (4)	R/P Ratio (4) ÷ (2) (5)	F/P Ratio (3) ÷ (2) (6)
1918	0.7	-	15.0	-	-
1919	0.8	-	15.0	-	-
1920	0.8	-	15.0	-	-
1921	0.7	-	15.0	-	-
1922	0.8	-	15.0	-	-
1923	1.0	-	15.0	-	-
1924	1.1	-	15.0	-	-
1925	1.2	-	23.0	-	-
1926	1.3	-	23.0	-	-
1927	1.4	-	23.0	-	-
1928	1.6	-	23.0	-	-
1929	1.9	-	23.0	-	-
1930	1.9	-	46.0	-	-
1931	1.7	-	46.0	-	-
1932	1.6	-	46.0	-	-
1933	1.6	-	46.0	-	-
1934	1.8	-	62.0	-	-
1935	1.9	-	62.0	-	-
1936	2.2	-	62.0	-	-
1937	2.4	-	62.0	-	-
1938	2.3	-	70.0	-	-
1939	2.5	-	70.0	-	-
1940	2.7	-	85.0	-	-
1941	2.8	-	113.8	-	-
1942	3.1	-	110.0	-	-
1943	3.4	-	110.0	-	-
1944	3.7	-	133.5	-	-
1945	3.9	-	144.3	-	-
1946	4.9	17.6	159.7	32.5	3.6
1947	5.6	10.9	165.0	29.5	1.9
1948	6.0	13.8	172.9	28.9	2.3
1949	6.2	12.6	179.4	28.9	2.0
1950	6.9	12.0	184.6	26.9	1.7
1951	7.9	16.0	192.8	24.3	2.0
1952	8.6	14.3	198.6	23.1	1.7
1953	9.2	20.3	210.3	22.9	2.2
1954	9.4	9.6	210.6	22.5	1.0
1955	10.1	21.9	222.5	22.1	2.2
1956	10.9	24.7	236.5	21.8	2.3
1957	11.4	20.0	245.2	21.4	1.7
1958	11.4	18.9	252.8	22.1	1.7
1959	12.4	20.6	261.2	21.1	1.7
1960	13.0	13.9	262.3	20.1	1.1
1961	13.5	17.2	266.3	19.9	1.3
1962	13.6	19.5	272.3	20.0	1.4
1963	14.5	18.2	276.2	19.0	1.3
1964	15.3	20.3	281.3	18.3	1.3
1965	16.3	21.3	286.5	17.6	1.3
1966	17.5	20.2	289.3	16.5	1.2
1967	18.4	21.8	292.9	15.9	1.2
1968	19.4	13.7	287.4	14.8	0.7
1969	20.7	8.4	275.1	13.3	0.4
1970	22.0	37.2	290.7	13.2	1.7
1971	22.1	9.8	278.8	12.6	0.4
1972	22.5	9.6	266.1	11.8	0.4
1973	22.6	6.8	250.0	11.1	0.3

* Includes gas in underground storage.
** Computed prior to rounding.
Sources: 1918-1945, Twentieth Century Petroleum Statistics, 1973, DeGolyer and MacNaughton, page 70. 1946-1973, American Gas Association.
Note : Production from 1918-1945 is marketed production. From 1946-1973 production includes all gas produced except gas reinjected for reservoir pressure maintenance.

Table 1-2

United States Natural Gas Supply Excluding Alaska *
1946-1973

(All Volumes in Trillions of Cubic Feet @ 14.73 Psia and 60^{O}F.)

Year (1)	Production (2)	Reserve Additions (3)	Proved Reserves (4)	R/P Ratio (4) ÷ (2)** (5)	F/P Ratio (3) ÷ (2)** (6)
1946	4.9	17.6	159.7	32.5	3.6
1947	5.6	10.9	165.0	29.5	1.9
1948	6.0	13.8	172.9	28.9	2.3
1949	6.2	12.6	179.4	28.9	2.0
1950	6.9	12.0	184.6	26.9	1.7
1951	7.9	16.0	192.8	24.3	2.0
1952	8.6	14.3	198.6	23.1	1.7
1953	9.2	20.3	210.3	22.9	2.2
1954	9.4	9.6	210.6	22.5	1.0
1955	10.1	21.9	222.5	22.1	2.2
1956	10.9	24.7	236.5	21.8	2.3
1957	11.4	20.0	245.2	21.4	1.7
1958	11.4	18.9	252.8	22.1	1.7
1959	12.4	20.6	261.2	21.1	1.7
1960	13.0	13.8	262.2	20.1	1.1
1961	13.4	16.4	265.4	19.8	1.2
1962	13.6	18.8	270.6	19.9	1.4
1963	14.5	18.1	274.5	18.9	1.2
1964	15.3	20.1	279.4	18.2	1.3
1965	16.2	21.2	284.5	17.5	1.3
1966	17.5	19.2	286.4	16.4	1.1
1967	18.4	21.1	289.3	15.7	1.1
1968	19.3	12.0	282.1	14.6	0.6
1969	20.6	8.3	269.9	13.1	0.4
1970	21.8	11.1	259.6	11.9	0.5
1971	21.9	9.4	247.4	11.3	0.4
1972	22.4	9.4	234.6	10.5	0.4
1973	22.5	6.5	218.3	9.7	0.3

*Data represents total U.S. natural gas supply prior to 1960. Alaska's natural gas supply was not reported until 1960. Includes gas in underground storage.

**Computed prior to rounding.

Source: A.G.A.

trillion cubic feet. With Alaska included, average annual additions have been approximately 17 trillion cubic feet. Although gas well drilling is on the upswing and the planned acceleration of offshore lease sales is a positive step toward developing the resource potential of these areas, many large new fields will have to be found and developed on a continuous basis if we are to attain or exceed the reserve addition levels cited above. This may be possible, however, if such areas as the Atlantic Offshore and continental shelf of Alaska are opened for leasing and the subsequent exploration and development programs prove highly successful.

Production

Annual natural gas production has increased steadily from less than one trillion cubic feet in 1918 to over 22 trillion cubic feet in 1973 (Table I-1). Annual increases were only nominal through 1954 with the major portion of the increase in production coming after that time. Since 1970 the annual production increases have become progressively smaller and production in 1973 increased less than one-half of one percent over 1972. This is probably indicative that our currently proved gas reserves in the lower 48 states are producing at or near capacity. Natural gas production in Alaska, which has been restricted due to the lack of market outlets, amounted to slightly more than 130 billion cubic feet in 1973, of which nearly one half was exported to Japan as LNG.

The 1973 total natural gas production of 22.6 trillion cubic feet was composed of 17.8 trillion cubic feet of non-associated gas and 4.8 trillion cubic feet of associated-dissolved gas. These proportions, about 80/20 percent, have remained relatively stable over the past ten years. Whether this relationship will continue in the lower 48 states will depend upon the relative success of efforts to develop our potential oil and gas supplies. Associated-dissolved gas from Alaska's North Slope could alter the established patterns of natural gas production components when this gas becomes available to markets in the lower 48 states.

For the short-term, the maintenance or increase of our current level of gas production will, in all likelihood, hinge on the development of additional onshore supplies, where there is little lag time between drilling and production.

Activity in the Gulf of Mexico, where there is a relatively well developed pipeline system, must be maintained at a high level.

For the longer-term, frontier areas such as the Atlantic Offshore, the Pacific Offshore, and Alaska must be developed.

Oil and Gas Well Drilling Trends

Historical drilling statistics indicate that total oil and gas well drilling reached a peak in this country in 1956. With the exception of an occasional slight reversal, drilling has been on a downward trend ever since. However, in spite of this continuing downward trend for total wells, gas well completions were higher in 1973 than any year since 1945. Indications are that the total drilling effort is now on an upward swing. During the first six months of 1974 there were 14,748 completions; 5,732 were oil wells, 3,606 gas wells and 5,410 dry holes. If this level of activity continues for the remainder of the year, total drilling for 1974 will be higher than any year since 1969.

Drilling for hydrocarbons can be divided into two general categories; development drilling, and exploratory drilling. Wells in the first category, which have the lowest degree of risk, are drilled to exploit or develop a hydrocarbon accumulation discovered by previous drilling. About 77 percent of the development wells drilled in 1973 were successful, and resulted in 9,283 oil wells, 5,485 gas wells and 4,358 dry holes.

Exploratory drilling, which is conducted for the purpose of extending the known limits of previously discovered reservoirs and to discover new hydrocarbon deposits in previously undiscovered reservoirs, can be divided into the five following classes: new-field wildcat, new-pool wildcat, deeper-pool test, shallower-pool test, and outpost or extension test. The degree of risk assumed by the operator is the highest for the new-field wildcat category and decreases to the outpost or extension test category, which represents the lowest risk for exploratory wells. About 20 percent of the total exploratory wells drilled in 1973 were successful, and resulted in 619 oil wells and 900 gas wells as compared to 5,947 dry holes. The following table compares total exploratory statistics for 1973 with the new-field wildcat and other exploratory categories.

Table I-3

Exploratory Wells Drilled-1973

Category	Oil Wells	Gas Wells	Dry Holes	Total
New-Field Wildcats	285	416	4,288	4,989
Other Exploratory	334	484	1,659	2,477
Total Exploratory	619	900	5,947	7,466

New-field wildcat discoveries totaled 701 which is equal to a success ratio of about 14 percent. Wells in this category are very important because they discover the new fields which are necessary to the maintenance of adequate oil and gas supplies.

Table I-4 and I-5 include data on total wells and total exploratory wells drilled from 1945 through 1973. The data in these tables show that although oil well drilling has decreased drastically since the mid-fifties, gas well drilling has been relatively steady and is currently exhibiting a sharp upward trend.

Potential Gas Supply

Potential gas resource estimates consist primarily of the undiscovered portion of the natural gas resource base. There have been many estimates made in the past of our potential gas resources. These estimates, which have been based on a wide variety of assumptions and methodologies, differ considerably in magnitude. In general, the potential estimates are concerned with gas that will be found and produced in the future under certain assumptions with regard to price and technology.

Two of the most often quoted potential gas resource estimates are those prepared by the Potential Gas Committee (PGC) and the U.S. Geological Survey (USGS). As defined by the Potential Gas Committee, potential supply is gas that will be found and proved by test wells. These wells may be drilled in the future under the assumed conditions of adequate but reasonable prices, and normal improvement in technology. The PGC, which makes biennial estimates of our potential gas supplies, divides its estimate into three

Table I-4

Total Wells Drilled for Hydrocarbons
(Footage Drilled in Thousands of Feet)

Year	Total* Wells	Footage	Average Depth	Oil Wells	Footage	Average Depth	Gas Wells	Footage	Average Depth	Dry Holes	Footage	Average Depth	Successful Wells (%)
1945	23,601	87,545	3,709	13,738	50,956	3,709	2,637	9,300	3,527	7,226	27,289	3,777	69.4
1946	27,975	97,393	3,481	15,962	56,632	3,548	3,510	11,801	3,362	8,503	28,960	3,406	69.6
1947	30,833	109,358	3,547	17,478	62,802	3,593	3,809	13,169	3,457	9,546	33,387	3,497	69.0
1948	36,659	131,187	3,579	21,760	77,307	3,553	3,387	12,312	3,635	11,512	41,567	3,611	68.6
1949	37,312	135,619	3,635	21,352	79,428	3,720	3,363	12,437	3,698	12,597	43,754	3,473	66.2
1950	42,050	157,358	3,742	23,812	92,695	3,893	3,439	13,685	3,979	14,799	50,978	3,445	64.8
1951	43,643	172,145	3,944	23,179	95,106	4,103	3,438	13,946	4,056	17,026	63,093	3,706	61.0
1952	44,563	184,134	4,132	23,290	98,147	4,214	3,514	15,257	4,342	17,759	70,730	3,983	60.1
1953	47,740	194,245	4,069	25,323	102,135	4,033	3,968	18,248	4,599	18,449	73,861	4,004	61.4
1954	51,109	208,009	4,070	28,141	113,362	4,028	4,038	18,857	4,670	18,930	75,790	4,004	63.0
1955	55,150	226,182	4,101	30,432	121,149	3,981	4,266	19,931	4,672	20,452	85,102	4,161	62.9
1956	57,170	233,280	4,080	30,528	120,351	3,942	4,531	22,738	5,018	22,111	90,191	4,079	61.3
1957	51,995	217,046	4,174	27,364	110,043	4,021	4,475	23,836	5,326	20,156	83,167	4,126	61.2
1958	46,941	193,304	4,118	23,774	93,105	3,916	5,005	25,556	5,106	18,162	74,643	4,110	61.3
1959	47,563	200,693	4,220	24,043	94,611	3,935	4,931	26,607	5,396	18,589	79,476	4,275	60.9
1960	45,547	192,078	4,217	22,233	86,538	3,892	5,129	28,199	5,498	18,185	77,341	4,253	60.1
1961	44,254	189,633	4,285	21,413	85,508	3,993	5,459	29,179	5,345	17,382	74,947	4,312	60.7
1962	44,158	194,634	4,408	21,727	88,432	4,070	5,353	28,950	5,408	17,078	77,253	4,524	61.3
1963	41,467	182,649	4,405	20,135	81,809	4,063	4,570	24,533	5,368	16,762	76,307	4,552	59.6
1964	42,293	187,420	4,431	19,905	80,463	4,042	4,694	25,597	5,453	17,694	81,359	4,598	58.2
1965	38,773	174,882	4,510	18,065	73,322	4,059	4,482	24,931	5,562	16,226	76,629	4,723	58.2
1966	35,730	165,420	4,630	16,216	67,430	4,158	4,321	25,636	5,933	15,193	72,353	4,762	57.5
1967	32,234	141,357	4,385	15,329	58,634	3,825	3,659	21,580	5,898	13,246	61,143	4,616	58.9
1968	30,599	144,970	4,738	14,331	59,517	4,153	3,456	20,716	5,994	12,812	64,737	5,053	58.1
1969	32,187	157,108	4,881	14,368	61,582	4,286	4,083	24,162	5,918	13,736	71,363	5,195	57.3
1970	28,120	139,266	4,953	13,020	57,092	4,385	3,840	22,889	5,961	11,260	59,285	5,265	60.0
1971	25,851	124,240	4,806	11,858	48,552	4,094	3,830	22,624	5,907	10,163	53,064	5,221	60.7
1972	27,291	134,602	4,932	11,306	48,534	4,293	4,928	26,766	5,431	11,057	59,303	5,363	59.5
1973	26,592	136,391	5,129	9,902	44,642	4,508	6,385	35,600	5,576	10,305	56,149	5,449	61.2

Sources: 1945-1966; World Oil, 1967-1973; AAPG-API

* Includes Alaska. Excludes service wells.

Note: These statistics may not include all wells drilled in a given year because AAPG statistical procedures may result in certain wells being held in a "suspense file" until all required well data has been made available. For additional detail see AAPG Bulletin on North American Developments published annually, usually in August.

Table I-5

Total Exploratory Wells Drilled for Hydrocarbons
(Footage Drilled in Thousands of Feet)

Year	Total* Wells	Footage	Average Depth	Oil Wells	Footage	Average Depth	Gas Wells	Footage	Average Depth	Dry Holes	Footage	Average Depth	Successful Wells (%)
1945	5,610	23,049	4,109	836	3,750	4,486	376	1,772	4,712	4,398	17,527	3,985	21.6
1946	5,759	22,338	3,879	762	3,455	4,534	375	1,832	4,885	4,622	17,052	3,689	19.7
1947	6,775	26,393	3,896	982	4,281	4,359	396	1,895	4,787	5,397	20,217	3,746	20.3
1948	8,013	32,751	4,087	1,098	4,883	4,447	365	2,306	6,319	6,550	25,562	3,903	18.3
1949	9,058	34,798	3,842	1,406	5,950	4,232	424	2,409	5,682	7,228	26,439	3,658	20.2
1950	10,306	40,175	3,898	1,583	6,862	4,335	431	2,356	5,466	8,292	30,957	3,733	19.5
1951	11,756	49,344	4,197	1,763	8,125	4,609	454	2,496	5,497	9,539	38,723	4,059	18.9
1952	12,425	55,615	4,476	1,776	8,491	4,781	559	3,394	6,071	10,090	43,731	4,334	18.8
1953	13,313	60,664	4,557	1,981	9,432	4,761	699	3,952	5,654	10,633	47,280	4,447	20.1
1954	13,100	59,601	4,550	1,985	9,409	4,740	726	4,399	6,059	10,389	45,792	4,408	20.7
1955	14,942	69,206	4,632	2,236	10,774	4,819	874	5,212	5,964	11,832	53,220	4,498	20.8
1956	16,207	74,337	4,587	2,267	11,111	4,901	822	5,179	6,301	13,118	58,047	4,425	19.1
1957	14,714	69,181	4,702	1,945	9,794	5,036	865	5,967	6,898	11,904	53,420	4,488	19.1
1958	13,199	61,484	4,658	1,745	8,712	4,993	822	5,472	6,657	10,632	47,300	4,449	19.4
1959	13,191	63,253	4,795	1,702	8,545	5,021	912	6,031	6,613	10,577	48,676	4,602	19.8
1960	11,704	55,831	4,770	1,321	6,829	5,170	868	5,466	6,298	9,515	43,535	4,575	18.7
1961	10,992	54,442	4,953	1,157	5,900	5,099	813	5,249	6,457	9,022	43,293	4,799	17.9
1962	10,797	53,616	4,966	1,211	6,205	5,124	771	5,187	6,728	8,815	42,223	4,790	18.4
1963	10,664	53,485	5,015	1,314	6,409	4,877	664	4,230	6,370	8,686	42,847	4,933	18.5
1964	10,747	55,497	5,164	1,219	6,715	5,509	577	4,204	7,285	8,951	44,578	4,980	16.7
1965	9,466	49,204	5,198	946	5,366	5,672	515	3,757	7,295	8,005	40,081	5,007	15.4
1966	10,313	55,223	5,355	1,030	5,880	5,708	578	4,881	8,445	8,705	44,462	5,108	15.6
1967	9,059	49,124	5,423	1,039	5,990	5,765	556	4,231	7,609	7,464	38,903	5,212	17.6
1968	8,879	50,958	5,739	863	5,036	5,835	430	3,320	7,720	7,586	42,603	5,616	14.6
1969	9,701	57,466	5,924	1,084	6,563	6,054	616	4,985	8,092	8,001	45,918	5,739	17.5
1970	7,693	45,253	5,882	790	5,055	6,399	481	3,675	7,639	6,422	36,524	5,687	16.5
1971	6,922	40,388	5,835	651	3,712	5,701	437	3,328	7,616	5,834	33,347	5,716	15.7
1972	7,539	45,944	5,975	684	4,002	5,851	601	4,592	7,641	6,254	36,500	5,836	17.0
1973	7,466	44,777	5,997	619	3,854	6,226	900	6,171	6,856	5,947	34,753	5,947	20.3

Source: AAPG - API

* Includes Alaska. Excludes stratigraphic and core tests.

Note: These statistics may not include all wells drilled in a given year because AAPG statistical procedures may result in certain wells being held in a "suspense file" until all required well data has been made available. For additional detail see AAPG Bulletin on North American Developments published annually, usually in August.

categories of decreasing reliance: probable, possible, and speculative supplies. Probable supply is associated with existing fields, and includes both discovered and undiscovered reserves. Possible supply is in undiscovered fields in areas of established production, and speculative supply is in untested territories or formations where no production is present, and the estimates are based on a minimum amount of information.

The USGS recently revised its estimates of potential gas supplies and adopted new definitions for mineral reserves and resources. Although the USGS terminology is different from that used by the PGC because it is used for all minerals and not exclusively for gas, general comparisons can be made. The USGS classification of indicated and inferred reserves is basically the same as the probable supply category used by the PGC. The USGS definitions for these two categories follow:

"Indicated Reserves: Reserves based partly upon specific measurements, samples, or production data, and partly from projection for a reasonable distance on geologic evidence."

"Inferred Reserves: Those reserves based upon broad geologic knowledge for which quantitative measurements are not available. Such reserves are those estimated to be recoverable in the future as a result of extensions, revisions of estimates, and deeper drilling in known fields."

The USGS classification of undiscovered recoverable resources, which includes "hypothetical and speculative" resources, is similar to the possible and speculative supply categories used by the PGC. The USGS definition is as follows:

"Undiscovered Recoverable Resources: Those quantities that may be reasonably expected to exist in favorable geologic settings, but which have not yet been identified by drilling. Exploration will permit the reclassification of such resources to the reserve category."

There is a high degree of uncertainty involved in trying to estimate the magnitude of undiscovered resources. This is especially true of oil and gas where wells must be drilled to determine if an area contains commercially recoverable hydrocarbons. This is certainly true of our

Atlantic Offshore area where no wells have been drilled to date. The following table includes a comparison of the PGC and USGS estimates.

It can be seen from the table that our potential gas resources based on the PGC and USGS estimates range from about 1,100 to over 2,200 trillion cubic feet. This compares to our current proved reserve supply of 250 trillion cubic feet and and our total discovered gas supply, through the end of 1973, of slightly over 700 trillion cubic feet. Total discoveries of 700 trillion cubic feet since the beginning of the industry in this country over 100 years ago are indicative of the effort that will be required to convert our potential gas resources (as estimated by PGC and the USGS) into commercially producible reserves.

Table I-6
Comparison of Potential Gas Resource Estimates
(Trillion Cubic Feet)

Area	Probable		Undiscovered		Total	
	PGC	USGS	PGC	USGS	PGC	USGS
Lower 48 States Onshore	154	93-177	396	500-1000	550	593-1177
Lower 48 States Offshore	58	22-43	172	225-450	230	247-493
Atlantic 1/	-	-	35	55-110	35	55-110
Gulf of Mexico	57	21-41	127	160-320	184	181-361
Pacific	1	1-2	10	10-20	11	11-22
Total Lower 48 States	212	115-220	568	725-1450	780	840-1670
Alaska	54	15-30	312	275-550	366	290-580
Total United States	266	130-250	880	1000-2000	1146	1130-2250

1/ The potential of Florida's Atlantic Continental Shelf is included with the Gulf of Mexico in the PGC estimate.

Sources: PGC estimate; "Potential Supply of Natural Gas in the United States, as of December 31, 1972," November, 1973.
USGS estimate. "USGS Releases Revised U.S. oil and Gas Resource Estimates," Department of Interior News Release, March 26, 1974.

II METHODOLOGY OF ESTIMATION

General Approach of the Oil and Natural Gas Task Forces and Its Conceptual Limitations

A complete state-of-the-art analysis of possible gas supplies under varying sets of economic and policy assumptions would have required lengthy and painstaking development of a methodology and its associated implementary software package, the complexity of which would have been in some measure directly related to the complexity of the petroleum industry. No adequate off-the-shelf means of accomplishing this objective currently exists. It was not possible to develop such a methodology because of the very short time allowed the supply task forces for completion of their work, although it was at the inception of the study and remains today a viable, even necessary option which should be vigorously pursued in the future. The expedient alternative was to adopt an already existing, if less adequate methodology, critically examine its assumptions, structure and data, and to the extent possible within the allowed time, alter those which were least desirable.

From among the handful of existing methodologies which allowed automated handling of the voluminous data used in analysis of possible national supply at the disaggregated level required by the PIB guidelines, the National Petroleum Council's methodology, with modifications, was selected for use by both the Oil and Natural Gas Task Forces. It consists of a series of interrelated, linear algorithms which calculate for a 15 year future period (starting in an initial year after which historical data are absent) and for 12 of the 14 NPC Regions (excluding both Alaskan regions in the case of gas and the North Slope region in the case of oil) the amounts of liquid and gaseous hydrocarbons which would be discovered and produced dependent upon realization of certain externally supplied regionalized and annualized inputs projective of the future. Most important of these input data are projections -- national and regional -- of levels of drilling activity, rates of discovery per foot of drilling given a successful drilling effort, probability of drilling success and rates of depletion of reserves.

Disregarding momentarily the myriad difficulties inherent in projecting future values of these key inputs, it is necessary first to indicate how they are used in the NPC methodology. The entire methodology is structured as a linear combination of inputs, intermediate values and "constants." The method is not an iterative model converging on any sort of an optimized output or use of resources, nor is it a stochastic (probabilistic) model properly reflecting the uncertainty of the estimates. If fact, the NPC methodology is not a true model at all, but primarily a bookkeeping procedure linearly converting inputs into outputs. The "model

program, specifically in the formulation of the input data. As an example of the type of calculations the program contains, for one region:

Gas Reserve Additions, year t = (Footage drilled for gas, year t) X (Volume of gas found per foot of successful drilling, year t) X (Probability of drilling success)

Gas Reserve Depletion, year t = (Proved reserves, year t) X (% Depletion, year t)

There is no result-associated measure available indicating whether any or all results obtained using the NPC methodology are likely to be in error or by how much; there is no measure other than gross qualitative inspection available with which to analyze the reasonableness of fit of the results to the real world. The NPC approach is such that it simply does not allow development of quantitative statistical measures of error; this deficiency is the primary shortcoming of the projections developed through use of this procedure by the Natural Gas Task Force -- no one really knows how reliable the results are.

Actual checks on the results consisted of a subjective, qualitative appraisal of trends in the outputs over time and space, and a semi-quantitative appraisal of the magnitudes of reserve additions and production with respect to both past experience and the maximum limits imposed by currently available estimates of the potential resources (those not yet discovered) remaining in each region. These kinds of checks on results are typically weak ones in the absence of gross errors. Historical experience reflects not only the historic character of resources but also has imbedded in it an inseparable element of past economic conditions. However, the past may have little to do with future discovery and production of gas. The rapid rate of change in economic conditions currently in evidence, the future form of which is entirely unclear at this time, indicate that the future might bear little relationship to the past.

To make matters worse, the currently available estimates of potential gas resources are diverse in magnitude and are now the targets of serious criticism as to the validity of their derivation. At best they may be characterized as rather gross extrapolations from knowledge of relatively well (not fully) explored areas to (hopefully) structurally and paleoenvironmentally similar but less well (or totally un-) explored areas. Assuming that such potential resource estimates as are available are not exceeded by the production results, it is still a matter of pure speculation that the levels of production called for in this report, in excess of current proved reserves, will be forthcoming as supplies. There are numerous possible non-economic production roadblocks. Further, it is unclear at what point in time (between exhaustion of current proved reserves and exhaustion of theoretical future reserves derived from the most optimistic potential resource estimates) production will be reduced or cease altogether due to adverse economic limitations tied to the character of the remaining resources and the nature of the energy market.

Because the success of the methodology in projecting possible future supply hinges entirely upon success in formulation of projections of the inputs to the modified NPC program, problems of formulation must be considered. First and foremost of these are the problems of basing projections upon historic experience, which have already been discussed in connection with review of outputs. The same comments apply to formulation of inputs. We are forced, in the absence of better methods, to extrapolate historic trends of the input variables into the future. This procedure runs a rather low risk of incorrect results for the first future year (or two) and increases in probability of error in an exponential manner as time progresses. Beyond the first few years, even in the best of all possible worlds, the results of extrapolation rapidly become nothing more than educated guesses. In many cases, statistical analyses of trends in the input variables have not been made by anyone, for a variety of reasons including, but not limited to, lack of data, coarseness of available data, lack of separability of factors affecting data trends (pure complexity) and lack of technical expertise in making of statistical analyses on the part of those in possession of data. As a consequence, the most recent trend of the data was continued into the future, usually in an assumed linear manner even in the knowledge that the variables may not behave linearly in time. The background of basic research needed to confidently formulate the future period variables simply did not, and does not, exist. Alternatively, the time to properly test multiple assumptions for each input variable to determine output sensitivity to input changes was not available.

The conclusion to be drawn from all these considerations is that the projections made here using the NPC methodology, while they represent our best educated effort at this time, are subject to serious error, and should be interpreted and used with extreme caution. They should most certainly not be used for any other purpose than those intended in the Project Independence Blueprint.

Program Updating and Modification

The NPC program was acquired by the Oil and Natural Gas Task Forces complete with an associated input data bank containing values of the required input variables through 1970. These were updated or revised by the Oil and Natural Gas Task Forces with values through the end of 1973. For gas, the production and discovery data were prepared by the Task Force staff and the cost data were updated, subject to task force review, by the consulting firm of LaRue, Moore, and Schafer.

The economics section of the NPC program was found to be methodologically inadequate for PIB purposes and was replaced by a new routine employing a discounted cash flow technique to determine price based on projected costs, projected and vintaged production of non-associated gas and its co-products, rate of return required, and appropriate tax calculations. This complex routine was devised and implemented by Mr. William Stitt of the consulting firm ICF, Inc., subject to task force review.

Coordination of Oil and Natural Gas Task Force Assumptions

Exploration for all gaseous and liquid hydrocarbons is carried out under nearly identical institutional constraints and using nearly identical technologies. For this reason, close coordination of assumptions between the Oil and Natural Gas Task Forces was required on matters such as the offshore leasing schedule, total drilling levels, and allocation of drilling effort to oil and gas targets. Identical general assumptions were arrived at by consensus at joint task force staff meetings.

Methodology of Estimation, Special Sources/Regions

Disaggregated investment and operating cost projections for Alaskan operations were supplied by the consulting firm of LaRue, Moore, and Schafer, based upon recent industry experience in North Slope operations and the projected costs of planned Alaskan activity, subject to task force review. Prices were calculated by a discounted cash flow technique at the required rate of return using schedules of production and well requirements prepared by the Natural Gas Task Force.

Investment and operating costs for gas from tight formations were derived via interpolation and removal of the inflation factor from data presented in the report of the Natural Gas Technology Task Force to the Technical Advisory Committee of the National Gas Survey, Federal Power Commission, dated April 1, 1973.

Investment and costs for gas occluded in coal seams were investigated and were determined to be properly part of the costs of coal mining rather than being creditable to production of the gas. Therefore, no cost estimates were made for gas from this source.

Approach to Resource Requirements

Quantities of raw and fabricated materials and amounts of labor required in order to attain the drilling and production levels projected in this study were estimated on a generalized basis. Since, for example, not all drilling rigs have identical depth capacities and all are not used in like environments, a relatively major portion of this effort consisted of computing multiple sets of coefficients covering possible combinations of the various inputs for subsequent multiplication by projected values in order to arrive at the materials and labor quantities. Sets of these coefficients for use in the materials projections, broken out by region, onshore/offshore, average regional hole depth, and successful/dry outcome were compiled by Mr. Donald Gilmore and Mr. Ira Mayfield of the Federal Energy Administration. Labor coefficients were provided, on a national basis, by Mr. Donald Eldridge of the Department of Labor.

Two methodologically identical computer programs were written to calculate the resource requirements, given the sets of coefficients and projections. One operated on the outputs of the NPC program, and the other on the results of projections for special sources/regions. Materials requirements were estimated based upon drilling footage and labor requirements were estimated based upon production. Additional labor requirements were calculated for geophysical exploration and for drilling based upon drilling footage and standard crew sizes and utilizations. Resource requirements were summarized in each target year in terms of their current level and their cumulative level from January 1, 1975, exclusive of the target year, for activities up to the point of custody transfer.

III PRODUCTION ASSUMPTIONS-CONVENTIONAL SOURCES-LOWER 48 STATES

Leasing Policies and Schedules

One of the primary factors to be considered in the development of future gas supplies in the lower 48 states is the leasing of acreage on the continental shelf. In 1973 about 3.8 trillion cubic feet of gas was produced from the lower 48 offshore areas. This was equivalent to about 17 percent of the lower 48's total gas production. Almost 85 percent, or 3.2 trillion cubic feet, of the offshore production came from the Outer Continental Shelf (OCS) which is under the jurisdiction of the Federal Government. There are approximately 160 million acres in the OCS of the lower 48 states out to water depths of 200 meters (656 feet). As of the end of 1973 only 9 million of the 160 million acres, about 5.6 percent, had been leased. (Although 15.1 million acres had been offered for lease).

For the BAU scenario an assumed OCS leasing program was prepared by the Natural Gas Task Force based on the Bureau of Land Management's (BLM) plan for offering 3 million acres per year through 1978. For the purpose of this scenario it was assumed that the plan of offering 3 million acres per year would continue after 1978 through 1990. Approximately 60 percent of the OCS acreage offered from 1954 through 1973 was actually leased. However, for the first 2 sales in 1974 only about 43 percent of the acreage offered was leased. In consideration of this relatively low current level of leasing it was assumed that 55 percent, or 1,650,000 acres of the acreage offered would be leased each year. Through 1978, the location of the lease sales was based on BLM's published schedule. After 1978 the ranking of the OCS areas was considered in the regional scheduling of lease sales. The ranking was based on a Department of the Interior survey of industry, other government agencies, environmental organizations and the public made for the purpose of setting forth the priorities for leasing in 17 areas of the OCS. The assumed leasing program for the BAU scenario is included as Table III-1 and the ranking of the OCS areas is included as Table III-2.

Under the BAU situation, leasing is scheduled for the Pacific offshore (NPC Region 2A) in 1975 and the Atlantic offshore (NPC Region 11A) in 1979.

Table III-1

ASSUMED OCS LEASING PROGRAM (BAU)
1971-1990
(Acres In Thousands)

Year	Offered: Acres Ranking	Leased: Acres of OCS	Leased: % Of Offered Areas	Region 6-A Gulf of Mexico: Western (3)	Region 6-A Gulf of Mexico: Central (1)	Region 6-A Gulf of Mexico: Eastern (6)	Region 2-A: Pacific (4)	Region 1-S Alaska: Gulf Of Alaska (2)	Region 1-S Alaska: Bering Sea (8)	Region 1-S Alaska: Cook Inlet (11)	Region 1-N: Beaufort Sea (9)	Region 11-A Atlantic: North (7)	Region 11-A Atlantic: Mid (5)	Region 11-A Atlantic: South (13)
							(10)		(12)		(14)			
1971	56	33	59		33/[28]		(16)		(15)					
1972	971	826	85		826/[29&30]		(17)							
1973	1,515	1,044	69		547/[31]	497/[32]								
1974	3,000	1,650	55		1,650/[33, 34&36]									
1975	3,000	1,650	55	550/[37]	550/[38]		550/[35]							
1976	3,000	1,650	55		1,100/[39&40] 1/		550/[41]							
1977	3,000	1,650	55		1,100/[42&44] 1/				550/[43]					
1978	3,000	1,650	55	550	550/[45] 1/					550/[46]				
1979	3,000	1,650	55		550 1/		550						550	
1980	3,000	1,650	55		550 1/			550				550		
1981	3,000	1,650	55		1,100 1/								550	
1982	3,000	1,650	55		550 1/		550		550					
1983	3,000	1,650	55		550 1/			550				550		
1984	3,000	1,650	55		550 1/				550					550
1985	3,000	1,650	55		550 1/				550				550	
1986	3,000	1,650	55		550 1/		550					550		
1987	3,000	1,650	55		550 1/			550						550
1988	3,000	1,650	55		550 1/				550		550			
1989	3,000	1,650	55		550 1/			275	275				550	
1990	3,000	1,650	55	—	550 1/	—	550	—	—	—	—	550	—	—
	53,542	29,953	56		15,103		3,300	1,925	3,025	550	550	2,200	2,200	1,100

Lease Sale Numbers [28] - [46].

1/ General Gulf of Mexico Sales.

Pacific Includes OCS Areas: (4) Southern California Borderland, (10) Santa Barbara Channel, (16) Northern & Central California, and (17) Washington & Oregon.
Bering Sea Includes OCS Areas: (8) Bristol Bay, (12) Bering Sea and (15) Southern Aleutian Shelf.
Beaufort Sea Includes OCS Areas: (9) Beaufort Sea and (14) Chukchi Sea.

Table III-2

Industry Ranking of OCS Areas

1. Central Gulf of Mexico
2. Gulf of Alaska
3. West Gulf of Mexico
4. Southern California Borderland
5. Mid-Atlantic
6. East Gulf of Mexico
7. North Atlantic
8. Bristol Bay
9. Santa Barbara
10. Beaufort Sea
11. Cook Inlet
12. Bering Sea
13. South Atlantic
14. Chukchi Sea
15. Southern Aleutian Shelf
16. Northern and Central California
17. Washington-Oregon

The assumed leasing program for the accelerated scenario considers the proposal for leasing 10 million acres in 1975. Based on tentative BLM plans, the 10 million acres were scheduled to be leased in 4 separate sales of approximately 2.5 million acres each. Two of the sales were scheduled for the Gulf of Mexico and one each in the Pacific offshore and the Gulf of Alaska. It was assumed that it would be necessary to offer at least 15 million acres in 1975 in order to actually lease 10 million. The task forces program assumed no leasing in 1976 with leasing to resume in 1977 at a rate of 3 million acres offered and increasing to 10 million acres offered annually by 1990. Again, as in the BAU scenario, except for 1975, it was assumed that 55 percent of the acreage offered would be leased. For the full 1974-1990 period the task force scheduled about 106 million acres to be offered with about 60 million acres to be leased. The latter figure is over 6 times the amount of all OCS acreage leased through the end of 1973. The accelerated assumed leasing program is included on Table III-3.

The availability of acreage is not considered to be a production constraint. The lease offerings and the amount of acreage scheduled for leasing are assumed to be sufficient to support the projected levels of production in both the BAU and accelerated situations. The levels of leasing beyond BLM's announced leasing schedules (through 1978 in the BAU and 1975 in the accelerated situations) are mere hypotheses and do not in any way constitute official plans or proposals for leasing in the OCS.

Drilling Rates

Until recently approximately 70 percent of the total drilling effort in the U.S. had historically been directed toward the development of oil supplies with 30 percent directed toward gas development. However, the drilling effort recently shifted toward the drilling of gas wells and in 1973 approximately 45 percent of total drilling was directed toward the development of non-associated gas supplies. This recent change in the historical gas-oil drilling relationship was the result of a continuation of the downward oil well drilling trend

ASSUMED OCS LEASING PROGRAM (Accelerated)
1971-1990
(Acres in Thousands)

Year	Offered Acres	Leased Acres	Leased % Of Offered	Region 6-A Gulf of Mexico Western	Region 6-A Gulf of Mexico Central	Region 6-A Gulf of Mexico Eastern	Region 2-A Pacific	Region 1-S Alaska Gulf Of Alaska	Region 1-S Alaska Bering Sea	Region 1-S Alaska Cook Inlet	1-N Beaufort Sea	Region 11-A Atlantic North	Region 11-A Atlantic Mid	Region 11-A Atlantic South
	Ranking Of OCS Areas - - -			(3)	(1)	(6)	(4)	(2)	(8)	(11)	9	(7)	(5)	(13)
1971	56	33	59		33/28/		(10)		(12)		14			
1972	971	826	35		826/29&30/		(16)		(15)					
1973	1,515	1,044	69		547/31/	497/32/	(17)							
1974	3,000	1,650	55		1,650/33,34&36/									
1975	15,000	10,000		2,500/37/	2,500/38/ 1/		2,500/35/	2,500/39/						
1976	-	-	-											
1977	3,000	1,650	55			825							825	
1978	3,000	1,650	55						1,100	550				
1979	5,000	2,750	55		1,375 1/							1,375		
1980	5,000	2,750	55	1,375				1,375						
1981	5,000	2,750	55		917								1,833	
1982	5,000	2,750	55			1,375			1,375					
1983	5,000	2,750	55	917			917					916		
1984	7,500	4,125	55		1,375			1,375					1,375	
1985	7,500	4,125	55			1,375			1,375			1,375		
1986	7,500	4,125	55	2,063			1,031							1,031
1987	7,500	4,125	55		1,375			1,375					1,375	
1988	7,500	4,125	55			2,063			2,062					
1989	10,000	5,500	55	916			916	917			917	917		917
1990	10,000	5,500	55		1,833 1/			458	1,833			459	917	
	109,042	62,228	57	7,771	12,431	6,135	5,364	8,000	7,745	550	917	5,042	6,325	1,948

Lease Sale Numbers /28/ - /39/.

1/ General Gulf of Mexico sales.
Pacific Includes OCS Areas: (4) Southern California Borderland, (10) Santa Barbara Channel, (16), Northern & Central California and (17) Washington & Oregon.
Bering Sea Includes OCS Areas: (8) Bristol Bay, (12) Bering Sea and (15) Southern Aleutian Shelf.
Beaufort Sea Includes OCS Areas (9) Beaufort Sea and (14) Chukchi Sea.

coupled with a sharp increase in the search for gas (Table III-4). The quantitative long range effect this sharp increase in gas drilling activity will have on non-associated gas reserve additions is not known. However, an increase in drilling does not necessarily increase quantitative findings in the same proportion. Much of the increase in activity has recently occurred in areas where gas reserves developed in relation to drilling activity are below the national average and gas wells of a more marginal quality (and lower reserves) are apparently being drilled and completed because higher gas prices now make them economically feasible.

The NPC model uses total gas well drilling footage plus allocated dry hole footage in the non-associated gas portion of the program as opposed to exploratory footage used in making the oil projections. The allocation of dry hole footage is based on the percent of successful gas well footage to the total successful oil and gas well footage on a regional basis. For example, if successful gas well footage is 40 percent of total successful footage in a region for a given year then 40 percent of the dry hole footage is allocated to gas. The Natural Gas Task Force computed the regional total gas well footage plus allocated dry hole footage for the years 1971-1973 in order to update the historical data. In addition, the cumulative footage by region was updated through 1973 in order to provide a base for making projections. These data are included in Table III-4.

The Natural Gas Task Force used two drilling rates for making projections of future non-associated gas supplies. The NPC high drilling rate was used for the BAU scenario since this schedule was felt to be representative of the drilling rates that could be attained under a continuation of the present natural gas regulatory environment. The drilling escalation factors used by NPC in their high drilling case for years 1971-1985 are shown in Table III-5. These factors were slipped to the years 1974-1988 for use in conjunction with the updated 1973 gas well footage. The drilling footage resulting from the use of these factors are also included in the table.

A different drilling escalation program was used for the accelerated development scenario, where escalation factors were used that result in a more rapid buildup of

Table III-4
Non-Associated Gas Well Footage 1/
(Thousands of Feet)

Region	Annual Footage 1970	1971	1972	1973	Percent Change 1970-1973	Cumulative Footage Through 1973	Regional Percentage
2	660	464	533	639	(3.2)	21,257	2.3
2A	-	-	-	-	-	328	0.0
3	1,468	3,042	2,371	3,139	113.8	55,611	6.1
4	1,717	2,172	2,477	2,626	52.9	34,329	3.7
5	3,778	3,653	3,710	7,029	86.0	77,893	8.5
6	16,201	14,442	18,069	20,962	29.4	391,641	42.7
6A	3,683	3,940	3,428	4,380	18.9	49,854	5.4
7	7,341	4,796	8,582	10,922	48.8	161,750	17.6
8+9	446	464	530	684	53.4	9,993	1.1
10	6,943	6,340	7,350	9,284	33.7	113,218	12.4
11	-	-	-	-	-	624	0.1
11A	-	-	-	-	-	-	-
Totals	42,237	39,313	47,050	59,665	41.3	916,498	100.0 2/

1/ Includes allocated dry hole footage.
2/ Does not add due to rounding.

Table III-5

Gas Drilling Escalation Factors And Projected Gas Well Footage

Year	Percent Annual Increase BAU	Percent Annual Increase Accelerated	Gas Well Footage * (Million Feet) BAU	Gas Well Footage * (Million Feet) Accelerated
1974	0.0	0.0	59.7	59.7
1975	5.0	8.3	62.6	64.6
1976	5.5	15.4	66.1	74.6
1977	6.0	13.3	70.1	84.5
1978	6.5	11.8	74.6	94.5
1979	7.0	5.3	79.8	99.5
1980	7.5	5.0	85.8	104.4
1981	8.0	4.8	92.7	109.4
1982	8.5	4.5	100.6	114.4
1983	9.0	4.3	110.6	119.3
1984	7.0	4.2	117.3	124.3
1985	5.0	4.0	123.2	129.3
1986	3.0	3.9	126.9	134.3
1987	1.0	3.7	128.1	139.3
1988	0.0	3.6	128.1	144.3

* Includes allocated dry hole footage.

drilling activity and in more cumulative footage being drilled than in the BAU scenario. The rationale for the utilization of a somewhat more optimistic drilling schedule in the accelerated development scenario is that the increased price incentives, which are assumed to be operative under this scenario, would result in increased drilling activity by producers. It will be noted on Table III-5 that gas well footage increases much more rapidly during the early years of the accelerated development case.

Although directionality has improved over the years in some areas it still is not possible to completely separate oil and gas well drilling activity. This is certainly true in areas such as the Atlantic Offshore where no drilling has taken place and in many regions where both oil and gas may be found in alternating reservoirs in the same field, or in the same reservoir within the boundaries of a geologic basin. Because of this, some non-associated gas may be found in the search for oil and some oil may be discovered when non-associated gas is the primary objective. The recent increase in oil prices should exert considerable effect on the drilling effort to discover new oil supplies and consequently impact gas reserve additions. The quantitative effect that oil price increases will have on future gas reserve additions, however, is speculative.

Drilling Distribution

The percentage drilling distributions by NPC region were updated through 1973 and served as the basis for the projections of regional drilling activity. The regional drilling distributions were projected for the 1974-1988 period after considering recent drilling trends and the assumed OCS leasing programs. The regional percentage drilling distributions for the BAU and ACC scenarios are included in Tables III-6 and III-7.

The basic difference in the two schedules, other than reflection of the timing and magnitude of the offshore lease sales, is attributed to the higher drilling escalation program used in the accelerated development case. As may be noted on Table III-8, which includes regional footage allocations, drilling in all areas through 1980 increased significantly in the accelerated program over the BAU

Table III-6

Percentage Allocation of Drilling Activity By Region
Non-Associated Gas-Lower 48 States
Business as Usual

	Actual			Projected						
Region	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
2	1.2	1.1	1.1	1.2	1.3	1.5	1.6	1.7	1.8	1.8
2A	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2
3	7.7	5.0	5.2	5.0	5.0	5.0	5.0	5.0	5.1	5.1
4	5.5	5.2	4.3	4.4	4.7	4.8	5.4	5.6	5.6	5.7
5	9.2	8.8	11.6	10.0	10.1	10.2	10.2	10.2	10.2	10.2
6	37.1	38.2	36.2	38.9	38.1	37.4	36.5	36.1	34.8	34.5
6A	10.0	7.2	7.2	7.4	9.3	10.6	11.3	12.1	13.0	13.1
7	12.1	18.0	18.0	17.0	16.0	15.3	15.3	15.3	15.6	15.6
8&9	1.2	1.1	1.1	1.1	1.0	0.9	0.8	0.7	0.7	0.7
10	16.0	15.4	15.3	15.0	14.5	14.0	13.5	12.8	12.6	12.6
11	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.4
11A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

	Projected							
Region	1981	1982	1983	1984	1985	1986	1987	1988
2	1.9	2.0	2.0	1.8	1.7	1.7	1.7	1.7
2A	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
3	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
4	5.7	5.7	6.0	6.1	6.2	6.2	6.2	6.2
5	10.4	10.5	10.6	10.7	10.6	10.6	10.6	10.6
6	33.8	33.3	32.6	32.1	32.1	32.1	32.1	32.1
6A	13.3	13.5	13.2	12.5	12.5	12.5	12.5	12.5
7	15.6	15.6	15.6	15.7	15.8	15.8	15.8	15.8
8&9	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
10	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
11	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
11A	0.2	0.3	0.9	2.0	2.0	2.0	2.0	2.0

Table III-7

Percentage Allocation of Drilling Activity by Region
Non-Associated Gas-Lower 48 States
Accelerated Development

	Actual			Projected						
Region	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
2	1.2	1.1	1.1	1.2	1.3	1.5	1.6	1.7	1.8	1.8
2A	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4
3	7.7	5.0	5.2	5.0	5.0	5.0	5.0	5.0	5.0	5.0
4	5.5	5.2	4.3	4.4	4.7	4.8	5.4	5.5	5.6	5.6
5	9.2	8.8	11.6	10.0	10.1	10.1	10.1	10.1	10.1	10.1
6	37.1	38.2	36.2	38.9	38.1	37.3	36.2	35.7	34.7	33.7
6A	10.0	7.2	7.2	7.4	9.3	10.6	11.5	12.5	13.5	14.0
7	12.1	18.0	18.0	17.0	16.0	15.3	15.3	15.2	15.2	15.2
8&9	1.2	1.1	1.1	1.1	1.0	0.9	0.8	0.7	0.7	0.7
10	16.0	15.4	15.3	15.0	14.5	14.0	13.5	12.7	12.2	12.3
11	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.4
11A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.8

	Projected							
Region	1981	1982	1983	1984	1985	1986	1987	1988
2	1.8	1.8	1.9	1.8	1.7	1.7	1.6	1.6
2A	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
3	5.0	4.9	4.9	4.9	4.9	4.8	4.8	4.7
4	5.6	5.5	5.7	5.8	5.9	5.9	5.9	5.9
5	10.1	10.1	10.1	10.2	10.1	10.0	9.9	9.9
6	32.8	32.1	31.1	30.6	30.4	30.3	30.2	30.1
6A	14.4	14.7	15.0	15.0	15.0	15.0	15.0	15.0
7	15.1	15.1	15.0	15.0	15.0	14.9	14.9	14.9
8&9	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
10	12.2	12.2	12.1	12.1	12.0	11.9	11.8	11.8
11	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
11A	1.3	1.9	2.5	2.9	3.3	3.8	4.2	4.4

Table III-8

Gas Well Drilling Footage By Region
(Thousands of Feet)

Business As Usual

Region	1974	1977	1980	1985	1988
2	716	1,121	1,545	2,094	2,178
2A	-	140	172	369	384
3	2,983	3,503	4,377	6,281	6,534
4	2,625	3,783	4,892	7,636	7,943
5	5,967	7,146	8,754	13,055	13,581
6	23,210	25,572	29,609	39,533	41,127
6A	4,415	7,917	11,243	15,395	16,015
7	10,143	10,719	13,389	19,459	20,243
8&9	656	560	601	862	897
10	8,950	9,458	10,814	15,518	16,143
11	-	140	343	493	512
11A	-	-	86	2,463	2,562
Total	59,665	70,059	85,824	123,157	128,120

Accelerated Development

Region	1974	1977	1980	1985	1988
2	716	1,352	1,880	2,198	2,309
2A	-	338	418	776	866
3	2,983	4,224	5,222	6,334	6,782
4	2,625	4,562	5,848	7,627	8,514
5	5,967	8,533	10,548	13,056	14,285
6	23,210	30,584	35,194	39,299	43,433
6A	4,415	9.716	14,621	19,391	21,645
7	10,143	12,926	15,874	19,391	21,500
8&9	656	676	731	905	1,010
10	8,950	11,406	12,845	15,513	17,027
11	-	169	418	517	577
11A	-	-	835	4,266	6,349
Total	59,665	84,486	104,434	129,272	144,297

program. By 1985 much of the increase in drilling between the two cases was allocated to the three offshore areas. This accounts for most of the difference between the two drilling allocations as shown on Tables III-6 and III-7.

Finding Rates

The finding rate relates to the amount of gas found per foot drilled and is one of the most important factors to be considered when making projections of future gas supply. The finding rates may vary considerably from region to region and may additionally be very erratic in a given region from year to year. However, a relatively smooth finding curve can be developed by plotting the ratio of cumulative reserves to cumulative footage drilled against time. Regional curves of this type were developed for each region that had sufficient historical data. The Natural Gas Task Force then projected these curves through the year 1988 and computed the annual findings per foot required to maintain the cumulative curves as projected. In Regions 8 and 11, where historical data were either too erratic or inadequate to develop usable cumulative curves, future finding rates were projected which appear compatible with the historic data. In Region 2-A (Pacific Offshore) finding rate data, although limited, indicates high finding rates are possible. In Region 11A (Atlantic Offshore) no historical data are available. In most regions the finding rates are initially high as the best and most obvious prospects are developed first. Later, as the region is more fully developed, the findings per foot drilled decrease as the resource base approaches depletion. However, because the Atlantic and Pacific Offshore areas are either in the initial or early stages of development the Natural Gas Task Force used relatively high non-declining finding rates for these two areas, at levels approximating 75 percent of the annual average finding rate for the Gulf of Mexico for the 1956-1973 period. Of all the projected lower 48 states regional finding rates used, those for Regions 2A and 11A are the most likely to deviate from the projected values; actual finding rates in these regions could prove to be either much higher, or lower, than projected. The regional finding rate data developed and utilized by the Task Force are included on Tables III-9 and III-10.

Table III-9

Projected Non-Associated Gas Reserves Added
Per Foot Drilled-Lower 48 States
Business As Usual

Year	Regions 2	2A	3	4	5	6	6A	7
1974	140	--	117	155	330	172	850	170
1975	140	-	117	150	320	170	820	165
1976	140	750	117	145	310	168	780	160
1977	139	750	117	140	300	166	750	155
1978	139	750	117	135	290	163	715	150
1979	138	750	117	131	280	156	675	145
1980	138	750	117	127	270	149	640	141
1981	137	750	117	123	260	142	600	138
1982	137	750	117	119	250	135	555	135
1983	135	750	115	116	240	128	515	132
1984	135	750	115	113	230	120	475	129
1985	133	750	115	110	220	112	440	126
1986	133	750	115	107	210	104	400	124
1987	130	750	115	104	200	94	370	122
1988	130	750	115	101	190	84	340	120

Year	Regions 8&9	10	11	11A
1974	75	80	-	-
1975	72	80	-	-
1976	69	80	20	-
1977	66	79	20	-
1978	63	79	20	-
1979	60	78	20	-
1980	57	78	20	750
1981	54	76	20	750
1982	51	75	20	750
1983	48	74	20	750
1984	45	73	20	750
1985	42	72	20	750
1986	39	71	20	750
1987	36	70	20	750
1988	33	69	20	750

Note: All Volumes in Mcf/foot

Table III-10

Projected Non-Associated Gas Reserves Added
Per Foot Drilled--Lower 48 States
Accelerated Development

Year	Regions 2	2A	3	4	5	6	6A	7
1974	140	-	117	155	330	172	850	170
1975	140	-	117	150	320	170	795	165
1976	140	750	117	144	308	168	770	159
1977	139	750	117	139	297	165	735	153
1978	138	750	117	133	285	160	695	147
1979	138	750	117	129	273	152	650	142
1980	137	750	117	124	260	145	605	139
1981	137	750	117	119	250	137	555	136
1982	136	750	115	116	240	130	510	132
1983	135	750	115	113	230	120	460	129
1984	133	750	115	110	220	114	435	127
1985	133	750	115	107	210	106	380	125
1986	130	750	115	104	200	96	340	123
1987	129	750	115	102	190	85	295	121
1988	127	750	115	99	183	76	250	119

Year	Regions 8&9	10	11	11A
1974	75	80	-	-
1975	72	80	-	-
1976	69	80	20	-
1977	66	79	20	-
1978	63	79	20	750
1979	60	78	20	750
1980	57	76	20	750
1981	54	75	20	750
1982	51	74	20	750
1983	48	73	20	750
1984	45	72	20	750
1985	42	71	20	750
1986	39	70	20	750
1987	36	69	20	750
1988	33	68	20	750

Note: All Volumes in Mcf/foot

At a given point in time, the finding rates are slightly lower in most regions in the accelerated case than in the BAU situation. This is due to the increased drilling activity which results in reaching a lower point on the regional cumulative finding curves at an earlier date than in the BAU case. This difference is the greatest in Region 6A (Gulf of Mexico) where the drilling increase was substantial in the accelerated case. There is no difference in the two cases for the Atlantic and Pacific Offshore areas because non-declining finding curves were utilized.

In connection with these finding rates, it should be noted that they are based on data, particularly in the offshore areas, that may not be complete. The unique characteristics of offshore oil and gas exploration and development may cause delays in the reporting of both new reserves and related drilling statistics. However, when cumulative data are used for constructing finding curves, the lack of recent statistics, in a rather well developed area such as the Gulf of Mexico, may have only minimal influence on the resulting curve.

Additions to Reserves

The cumulative non-associated additions of new reserves for the two scenarios for each of the NPC regions in the lower 48 states were determined by the Natural Gas Task Force to be of reasonable magnitude when compared to natural gas resource estimates. Table III-11 includes a comparison of the cumulative non-associated reserve additions (1974-1988) by region for both scenarios with corresponding estimates of undiscovered non-associated gas resources. It may be noted that in one case, the accelerated scenario in Region 2A, reserve additions exceeded the undiscovered resource estimate. However, estimates of undiscovered natural gas resources in the Pacific offshore area are highly speculative and one estimator places them as high as 69 trillion cubic feet. 1/

Table III-12 includes all natural gas reserve additions by cardinal years for the lower 48 states. The non-associated additions are based on projections by the Natural

1/ Moody, J.D. "U.S. Oil-Policy Riddle: How Much Left to Find," The Oil and Gas Journal, 9-16-74, p. 27.

Table III-11

Projected Non-Associated Reserve Additions Vs. Non-associated Resource Estimates-Lower 48 States
(Trillion Cubic Feet)

Region	Cumulative N.A. Reserve Additions BAU	Cumulative N.A. Reserve Additions Accelerated	Undiscovered N.A. Gas Resources *
2	3.3	3.6	17.6
2A	2.6	5.9	3.3
3	8.4	9.1	32.3
4	9.8	10.5	41.6
5	36.9	38.9	74.3
6	63.6	67.1	186.1
6A	94.4	107.0	156.4
7	30.7	32.8	118.5
8+9	.6	.6	12.1
10	13.7	14.8	62.9
11	.1	.1	4.6
11A	10.5	24.9	54.5
Total	274.7	315.3	764.2

* U.S. Energy Outlook, December 1972, Table 47, page 91.

Table III-12

Natural Gas Reserve Additions
Lower 48 States
(Trillion Cubic Feet)

Business As Usual

Region	Non-Associated 1974	1977	1980	1985	1988	Associated-Dissolved 1974	1977	1980	1985	1988	Total 1974	1977	1980	1985	1988
2	.100	.156	.213	.278	.283	.029	.047	.054	.065	.070	.129	.203	.267	.343	.353
2A	--	.105	.129	.277	.288	.027	.121	.233	.309	.353	.027	.226	.362	.586	.641
3	.349	.410	.512	.722	.751	025	.026	.027	.034	.040	.374	.436	.539	.756	.791
4	.407	.530	.621	.840	.802	.036	.064	.075	.082	.080	.443	.594	.696	.922	.882
5	1.969	2.144	2.364	2.872	2.580	.160	.179	.193	.223	.239	2.129	2.323	2.557	3.095	2.819
6	3.992	4.245	4.412	4.428	3.455	.280	.324	.345	.380	.368	4.272	4.569	4.757	4.808	3.823
6A	3.753	5.938	7.195	6.774	5.455	.550	.607	.788	.950	.937	4.303	6.545	7.983	7.724	6.392
7	1.724	1.661	1.888	2.452	2.429	.082	.063	.068	.082	.088	1.806	1.724	1.956	2.534	2.517
8&9	.049	.037	.034	.036	.030	--	--	--	--	--	.049	.037	.034	.036	.030
10	.716	.747	.843	1.117	1.114	.018	.021	.028	.033	.037	.734	.768	.871	1.150	1.151
11	--	.003	.007	.010	.010	.001	.006	.010	.016	.020	.001	.009	.017	.026	.030
11A	--	--	.064	1.847	1.922	--	--	.006	.043	.149	--	--	.070	1.890	2.071
Total	13.059	15.976	18.282	21.653	19.119	1.208	2.458	1.827	2.217	2.381	14.267	17.434	20.109	23.870	21.500

Accelerated Development

Region	Non-Associated 1974	1977	1980	1985	1988	Associated-Dissolved 1974	1977	1980	1985	1988	Total 1974	1977	1980	1985	1988
2	.100	.188	.258	.292	.293	.028	.046	.052	.064	.069	.128	.234	.310	.356	.362
2A	--	.253	.313	.582	.649	.064	.282	.530	.659	.739	.064	.535	.843	1.241	1.388
3	.349	.494	.611	.728	.780	.025	.026	.026	.033	.039	.374	.520	.637	.761	.819
4	.407	.634	.725	.816	.843	.035	.062	.073	.081	.079	.442	.696	.798	.897	.922
5	1.969	2.534	2.742	2.742	2.614	.155	.174	.187	.218	.233	2.124	2.708	2.929	2.960	2.847
6	3.992	5.046	5.103	4.166	3.301	.272	.314	.336	.372	.362	4.264	5.360	5.439	4.538	3.663
6A	3.753	7.141	8.846	7.368	5.411	.692	.750	.952	1.051	1.071	4.445	7.891	9.798	8.419	6.482
7	1.724	1.978	2.206	2.424	2.559	.079	.062	.066	.079	.085	1.803	2.040	2.272	2.503	2.644
8&9	.049	.045	.042	.038	.033	--	--	--	--	--	.049	.045	.042	.038	.033
10	.716	.901	.976	1.101	1.158	.017	.020	.028	.032	.036	.733	.921	1.004	1.133	1.194
11	--	.003	.008	.010	.012	.001	.006	.010	.016	.020	.001	.009	.018	.026	.032
11A	--	--	.627	3.199	4.762	--	.067	.138	.247	.298	--	.067	.765	3.446	5.060
Total	13.059	19.217	22.457	23.466	22.415	1.368	1.809	2.398	2.852	3.031	14.427	21.026	24.855	26.318	25.446

Gas Task Force and the associated-dissolved additions are based on Oil Task Force projections. These reserve addition projections are the direct result of utilizing the drilling rates and finding curves of each task force. The sensitivity of the computations to utilizing alternate non-associated gas finding rates is illustrated in Chapter VI.

Reserve to production (R/P) ratios of non-associated gas supplies by region were also monitored to assure maintenance at levels high enough to support scheduled production. Table III-13 shows calculated R/P ratios by region for the cardinal years.

Rates of Production

The production depletion rates for old gas (year-end 1973 reserves) used by the Natural Gas Task Force for each of the lower 48 regions are included in Table III-14. This table is based on the production depletion schedule used by the NPC for reserves on hand at the end of 1970. However the reserves have been updated to the end of 1973 and the depletion rates for the years 1971-1973 have been deleted. The regional depletion rates were then adjusted to be more in line with actual 1973 depletion rates and extended through 1988 by the Natural Gas Task Force.

For new gas, the depletion schedule used by the NPC was adopted by the Natural Gas Task Force. This schedule is included as Table III-15.

Table III-16 indicates projected total marketed gas production for both scenarios for the lower 48 states. The associated-dissolved production is based on Oil Task Force projections and the non-associated production projections were prepared by the Natural Gas Task Force. Non-associated marketed production for 1974 is projected to be slightly less than the 16,635 billion cubic feet recorded in 1973. Total non-associated production is not projected to exceed the 1973 level until after 1980 and 1977 in the BAU and ACC scenarios, respectively. In general, in both scenarios non-associated production is projected to increase from 1974 to 1988 in all regions except Regions 6 and 7. In these two regions drilling was not increased sufficiently to overcome the declining finding rates.

Total associated-dissolved production, as projected by the Oil Task Force, is lower in 1988 than in 1974 in both scenarios. However significant regional increases in associated-dissolved production are recorded in the three offshore regions (2A, 6A and 11A) in both scenarios. The overall effect of the general decline in associated-dissolved production offsets some of the increases in non-associated production

Table III-13
Non-Associated Gas Reserve to Production Ratios
(Associated)

Region	Actual 1973	Projected 1974	1977	1980	1985	1988
2	9.1	9.0	8.5	9.4	9.3	9.4
2A	10.7	9.0	20.2	13.7	11.4	10.7
3	14.8	14.4	12.9	12.7	12.8	12.7
4	14.5	13.0	12.5	13.1	12.6	12.4
5	7.3	7.2	9.0	9.1	8.7	8.5
6	9.4	9.1	8.8	8.7	8.0	7.6
6A	9.1	9.0	10.4	10.5	9.1	8.2
7	9.5	9.0	8.3	8.3	8.1	8.2
8&9	23.2	21.0	15.0	14.3	13.8	13.4
10	10.7	11.2	10.7	10.2	10.3	10.9
11	0.0	0.0	52.0	17.4	11.6	10.8
11A	0.0	0.0	0.0	0.0	64.3	42.8
Lower 48 States	9.4	9.4	9.7	9.8	9.6	9.6

Table III-14
Percent Reserves Produced from Current Reserves (1973)
Non-Associated Gas (Old Gas)

	Region											
Year	2	2A	3	4	5	6	6A	7	8	10	11	11A
Current Res. (Tcf)	2.2	0.3	9.4	4.9	15.4	66.7	32.2	31.2	0.5	4.2	0.0	0.0
	Percent Reserves Produced											
1974	10.5	10.0	6.7	7.7	13.7	10.5	11.2	10.5	5.0	9.6	0.0	0.0
1975	10.2	9.0	6.6	7.5	12.4	9.8	9.9	10.2	6.3	9.6	0.0	0.0
1976	9.8	8.1	6.4	7.2	10.3	9.1	9.1	9.4	5.8	8.9	0.0	0.0
1977	8.6	7.2	6.3	7.0	8.6	8.3	8.3	8.6	5.2	8.2	0.0	0.0
1978	7.5	5.6	6.1	6.2	7.7	7.5	7.6	7.8	4.8	7.7	0.0	0.0
1979	6.7	4.9	5.5	5.6	6.9	6.7	6.8	6.9	4.3	7.1	0.0	0.0
1980	5.9	4.4	5.1	5.1	6.2	6.1	6.1	6.2	4.0	6.7	0.0	0.0
1981	5.3	4.0	4.6	4.7	5.7	5.3	5.3	5.7	3.6	6.3	0.0	0.0
1982	4.6	3.6	4.2	4.3	5.1	4.8	4.8	5.1	3.4	5.8	0.0	0.0
1983	4.2	3.2	3.9	3.9	4.6	4.4	4.4	4.6	3.1	5.2	0.0	0.0
1984	3.5	2.9	3.5	3.6	4.0	3.9	3.9	4.0	2.8	4.6	0.0	0.0
1985	3.0	2.7	3.2	3.3	3.6	3.4	3.4	3.6	2.6	3.9	0.0	0.0
1986	2.5	2.0	2.9	2.9	3.2	3.0	3.0	3.2	2.4	3.4	0.0	0.0
1987	2.0	1.3	2.8	2.8	2.8	2.7	2.7	2.8	2.3	2.9	0.0	0.0
1988	1.6	-	2.5	2.6	2.5	2.3	2.3	2.5	2.1	2.0	0.0	0.0

Table III-15

Percent Reserves Produced from New Reserves
Non-Associated Gas

Year	Region 2	2A	3	4	5	6	6A	7	8	10	11	11A
					Percent Reserves Produced							
T + 1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
T + 2	10.0	10.0	6.7	6.7	10.0	10.0	10.0	10.0	9.5	9.5	10.0	0.0
T + 3	9.0	9.0	6.7	6.7	9.0	9.0	9.0	9.0	8.4	8.4	9.0	5.0
T + 4	8.0	8.0	6.7	6.7	8.0	8.0	8.0	8.0	7.5	7.5	8.0	4.9
T + 5	7.0	7.0	6.6	6.6	7.0	7.0	7.0	7.0	6.7	6.7	7.0	[illegible]
T + 6	7.0	7.0	6.4	6.4	7.0	7.0	7.0	7.0	6.0	6.0	7.0	4.3
T + 7	7.0	7.0	5.8	5.8	6.3	7.0	7.0	6.3	5.4	5.4	6.3	4.1
T + 8	6.7	6.7	5.2	5.2	5.5	6.7	6.7	5.5	4.8	4.8	5.5	3.9
T + 9	5.8	5.8	4.7	4.7	4.9	5.8	5.8	4.9	4.4	4.4	4.9	3.7
T + 10	5.0	5.0	4.3	4.3	4.4	5.0	5.0	4.4	4.0	4.0	4.4	3.5
T + 11	4.4	4.4	3.9	3.9	3.9	4.4	4.4	3.9	3.6	3.6	3.9	3.4
T + 12	3.8	3.8	3.6	3.6	3.5	3.8	3.8	3.5	3.3	3.3	3.5	3.2
T + 13	3.5	3.5	3.2	3.2	3.1	3.5	3.5	3.1	3.0	3.0	3.1	3.0
T + 14	3.0	3.0	3.0	3.0	2.8	3.0	3.0	2.8	2.8	2.8	2.8	2.9
T + 15	2.6	2.6	2.7	2.7	2.6	2.6	2.6	2.6	2.5	2.5	2.6	2.7

Table III-16

Marketed Natural Gas Production *
Lower 48 States
(Trillion Cubic Feet)

Business As Usual

Region	Non-Associated 1974	1977	1980	1985	1988	Associated-Dissolved 1974	1977	1980	1985	1988	Total 1974	1977	1980	1985	1988
2	.216	.202	.184	.208	.221	.163	.138	.126	.119	.102	.379	.340	.310	.327	.323
2A	.028	.025	.045	.113	.155	.013	.020	.054	.137	.190	.041	.045	.099	.250	.345
3	.592	.612	.586	.578	.609	.041	.040	.039	.041	.043	.633	.652	.625	.619	.652
4	.353	.394	.412	.503	.574	.162	.146	.143	.150	.153	.515	.540	.555	.653	.727
5	1.972	1.687	1.807	2.118	2.284	1.014	.811	.667	.485	.352	2.986	2.498	2.474	2.603	2.636
6	6.544	6.080	5.605	5.158	4.912	1.198	1.004	.935	1.058	1.178	7.742	7.084	6.540	6.216	6.090
6A	3.377	3.531	4.244	5.630	5.966	.521	.513	.567	.703	.756	3.898	4.044	4.811	6.333	6.722
7	3.070	2.880	2.544	2.333	2.320	.513	.420	.329	.188	.095	3.583	3.300	2.873	2.521	2.415
8&9	.023	.034	.035	.035	.035	--	--	--	--	--	.023	.034	.035	.035	.035
10	.375	.479	.562	.683	.742	.024	.023	.025	.032	.036	.399	.502	.587	.715	.778
11	--	--	.001	.004	.005	.001	.001	.002	.007	.011	.001	.001	.003	.011	.016
11A	--	--	--	.020	.213	--	--	--	.009	.023	--	--	--	.029	.236
Total	16.550	15.924	16.025	17.383	18.036	3.650	3.116	2.887	2.929	2.939	20.200	19.040	18.912	20.312	20.975

Accelerated Development

Region	Non-Associated 1974	1977	1980	1985	1988	Associated Dissolved 1974	1977	1980	1985	1988	Total 1974	1977	1980	1985	1988
2	.216	.203	.195	.225	.238	.163	.138	.126	.119	.101	.379	.341	.321	.344	.339
2A	.028	.031	.091	.251	.345	.013	.033	.114	.296	.404	.041	.064	.205	.547	.749
3	.592	.615	.608	.614	.640	.041	.040	.039	.040	.043	.633	.655	.647	.654	.683
4	.353	.398	.437	.540	.600	.162	.146	.142	.149	.152	.515	.544	.579	.689	.752
5	1.972	1.704	1.931	2.261	2.356	1.014	.810	.666	.484	.351	2.986	2.514	2.597	2.745	2.707
6	6.544	6.116	5.856	5.449	5.066	1.198	1.001	.930	1.052	1.172	7.742	7.117	6.786	6.501	6.238
6A	3.377	3.560	4.635	6.388	6.717	.521	.561	.653	.811	.858	3.898	4.121	5.288	7.199	7.575
7	3.070	2.894	2.642	2.464	2.413	.513	.418	.328	.186	.094	3.583	3.312	2.970	2.650	2.507
8&9	.023	.034	.037	.038	.038	--	--	--	--	--	.023	.034	.037	.038	.038
10	.375	.486	.607	.739	.781	.024	.023	.025	.032	.036	.399	.509	.632	.771	.817
11	--	--	.001	.004	.006	.001	.001	.002	.007	.011	.001	.001	.003	.011	.017
11A	--	--	--	.168	.509	--	--	--	.121	.173	--	--	--	.289	.682
Total	16.550	16.041	17.040	19.141	19.709	3.650	3.171	3.025	3.297	3.395	20.200	19.212	20.065	22.438	23.104

* Represents all gas produced excluding gas used for reservoir pressure maintenance and gas used for field use. Non-associated gas production has been reduced approximately 6 percent and associated-dissolved gas production has been reduced approximately 13 percent to reflect the historical rate of gas lease use, fuel use and losses.

IV PRODUCTION ASSUMPTIONS-SPECIAL SOURCES AND REGIONS

Alaska-North

North Alaska is considered to include all of the onshore area north of the Brooks Mountain Range and the continental shelf areas of the Beaufort and Chukchi Seas. Offshore development for North Alaska is not projected to begin until the late 1980's (Tables III-1 and III-3). Leasing, in addition to acreage currently under lease, is assumed to be adequate to support the projected development of non-associated gas supplies on the North Slope. Additionally, it is assumed that the Naval Petroleum Reserve No. 4 will be opened for exploration under accelerated conditions and both oil and natural gas supplies will be developed.

Three projections of non-associated gas supplies were prepared for both the BAU and accelerated scenarios for North Alaska. These projections were prepared outside of the NPC model by the Natural Gas Task Force. In addition, six projections of associated-dissolved gas supplies were prepared by the Natural Gas Task Force. These projections were coordinated with the oil production projections made by the Oil Task Force. The basic assumptions for the North Slope projections are discussed below.

Well Depths

The average depth of the wells drilled on the North Slope for gas are projected to increase from 10,400 feet in 1974 to 12,190 feet by 1988. This range is used for both the BAU and accelerated situations and is based on NPC's well depth projections.

Finding Rate

It was assumed that average additions of new non-associated gas reserves would be 101 Bcf per successful well for both the BAU and accelerated situations. This was the NPC's high finding rate for non-associated gas in Alaska. Based on a 20-year, or 5 percent depletion rate, each successful well would be capable of producing 13.8 million cubic feet per day for 20 years.

Success Ratio

The success ratio used for the BAU scenario was 67 percent compared to 50 percent for the accelerated situation. Although fewer wells are projected to be drilled in the BAU scenario, the Natural Gas Task Force concluded that these wells would have a higher success ratio because only the most promising prospects would be explored. In the accelerated situation more wells are projected to be drilled as a result of additional pipeline or LNG outlets for non-associated gas production. This increase in drilling activity would probably result in the drilling of less attractive prospects causing a decline in the success ratio. Regardless of which success ratio is used, when combined with a finding rate of 101 Bcf per successful well, very high productivities result. However, a high finding rate is a necessity in order for the non-associated natural gas operation in Alaska to be commercially viable.

Drilling Rates

Drilling rates for non-associated gas on the North Slope are projected at relatively low levels in comparison with drilling in the lower 48 states. This is because of the high cost of drilling wells which eliminates the drilling of prospects that would be excellent financial ventures in the lower 48 states. Additionally, the primary thrust on the North Slope to date has been the development of oil supplies with no proved non-associated gas reserves included in the American Gas Associations' statistics at the end of 1973. Table IV-1 includes projected footage and number of wells for each of the six cases annually for the 1974-1978 period.

Additions to Reserves

Non-associated reserve additions as projected for the North Slope are a function of the finding rate of 101 BCf found per successful well drilled and the number of successful wells projected for each of the six cases. In the most optimistic

Table IV-1
North Alaska
Projected Non-Associated Gas Well Footage and Number of Well Drilled
1974-1978

Year	Business As Usual			Accelerated		
	Low	Medium	High	Low	Medium	High
Footage (1,000')						
1974	10	10	12	22	24	24
1975	21	32	38	69	77	84
1976	32	32	41	72	82	90
1977	43	65	74	125	148	163
1978	44	76	96	158	192	211
1979	44	88	110	166	208	229
1980	45	89	123	176	227	250
1981	45	90	136	183	243	268
1982	34	91	137	188	255	280
1983	35	92	139	192	262	289
1984	35	93	140	194	265	291
1985	35	94	142	194	265	291
1986	36	95	143	192	265	291
1987	36	96	145	188	265	291
1988	24	98	146	183	265	291
Wells						
1974	1	1	1	2	2	2
1975	2	3	4	7	7	8
1976	3	3	4	7	8	8
1977	4	6	7	12	14	15
1978	4	7	9	14	18	19
1979	4	8	10	15	19	21
1980	4	8	11	16	20	22
1981	4	8	12	16	21	24
1982	3	8	12	16	22	24
1983	3	8	12	17	23	25
1984	3	8	12	17	23	25
1985	3	8	12	16	22	25
1986	3	8	12	16	22	24
1987	3	8	12	16	22	24
1988	2	8	12	15	22	24

situation, the accelerated "high" case, cumulative non-associated additions of 14.7 Tcf were projected. This is only a small fraction of Alaska's potential gas resources of 366 Tcf as estimated by the Potential Gas Committee. The USGS estimates potential gas resources for Alaska ranging from 322-612 Tcf. Table IV-2 lists the projected non-associated reserve additions for each of the six cases for the North Slope.

Rates of Production

All marketable gas production on the North Slope is dependent upon a natural gas pipeline outlet. Since all of the reported proved gas reserves on the North Slope are associated-dissolved gas in the Prudhoe Bay field, gas production is also dependent upon the completion of an oil pipeline. The current construction schedule calls for the completion of the oil pipeline in 1977 with oil production commencing that year.

Currently there are two applications pending before the Federal Power Commission requesting authorization for the construction of pipelines to transport the Prudhoe Bay associated-dissolved gas. Alaskan Arctic Gas Pipeline Company proposes to construct and operate a 48-inch pipeline approximately 195 miles in length from the Prudhoe Bay area to the international boundary where the pipeline will connect with Canadian Arctic Gas Pipeline Limited's pipeline. The Alaskan segment of this pipeline would have an initial capacity of 2.25 Bcf per day with an ultimate capacity of 4.5 Bcf per day.

The other proposal, by the El Paso Alaska Company, calls for the construction of an 809 mile, 42-inch pipeline running from Prudhoe Bay to Gravina Point on the Alaskan south coast. This line is designed to receive up to 3.5 Bcf of gas daily at Prudhoe Bay. The gas would be transported from South Alaska to the Westcoast as LNG.

It is not known if either of these currently proposed pipelines will ultimately be constructed. Therefore it was assumed by the Natural Gas Task Force, for the BAU scenario, that one gas pipeline would be constructed extending

Table IV-2
North Alaska
Projected Non-Associated Reserve Additions
(Billions of Cubic Feet)

	Business As Usual			Accelerated		
Year	Low	Medium	High	Low	Medium	High
1974	68	68	68	101	101	101
1975	135	203	271	353	353	404
1976	203	203	271	353	404	404
1977	271	406	473	606	707	758
1978	271	474	609	707	909	960
1979	271	541	677	758	960	1,060
1980	271	541	744	808	1,010	1,111
1981	271	541	812	808	1,060	1,212
1982	203	541	812	808	1,111	1,212
1983	203	541	812	859	1,161	1,265
1984	203	541	812	859	1,161	1,265
1985	203	541	812	808	1,111	1,265
1986	203	541	812	808	1,111	1,212
1987	203	541	812	808	1,111	1,212
1988	203	541	812	758	1,111	1,212
Total	3,182	6,764	9,609	10,202	13,381	14,653

from Prudhoe Bay either to the Canadian border or to the south coast of Alaska, and that the resulting pipeline (through looping) would have a maximum capacity of approximately 5.1 Bcf per day by 1988. In the accelerated scenario a second gas pipeline was assumed to be in operation by 1983. The combined capacity of the two lines was assumed to approximate 8.7 Bcf per day by 1988.

Associated-dissolved gas production was determined by using projected gas-oil ratios keyed to the Oil Task Force's oil production schedule. The GOR's used with certain levels of oil production projected for the first oil pipeline are shown in Table IV-3. The same schedule was also used for the second pipeline after adjustments for the date of initial production were made.

The projected non-associated gas production was dependent upon both available pipeline capacity and well capabilities. As scheduled, each producing well will be producing an average of 15-17 million cubic feet per day in 1988. Based on the assumptions used, the wells should be able to produce at higher rates if pipeline capacity is available.

Non-associated gas wellhead production was reduced six percent to cover lease use, fuel use and losses. This shrinkage factor used for the non-associated gas production, which is currently speculative, could prove to be conservative if significant quantities of carbon dioxide, or other non-hydrocarbon gases, are contained in the projected non-associated gas reserve additions. Data furnished by the FEA indicates that shrinkage of the associated-dissolved gas production from the Prudhoe Bay field could amount to approximately 26 percent of which about 13 percent would be for field use, and 13 percent to account for the carbon dioxide contained in the gas stream. Table IV-4 includes projected natural gas production from the North Slope for the cardinal years.

Table IV-3

Year	Oil Production MMB/d *	Producing GOR Ft^3/Bbl *	A-D Gas Production Total Bcf/d	A-D Gas Production After Shrinkage Bcf/d
1977	1.200	800	**	**
1988	1.200	950	**	**
1979	1.600	1,100	1.760	1,302
1980	2.000	1,250	2.500	1.850
1981	2.000	1,400	2.800	2.072
1982	2.000	1,550	3.100	2.294
1983	2.000	1,700	3.400	2.516
1984	2.000	1,850	3.700	2.738
1985	2.500	2,000	5.000	3.700
1988	2.500	2,000	5.000	3.700

* Data furnished by the Oil Task Force.

** Reinjected

Table IV-4

North Alaska
Projected Annual Marketed Gas Production
(Billions of Cubic Feet)

Year	Business As Usual			Accelerated		
	Low	Medium	High	Low	Medium	High
			Non-Associated			
1974	-	-	-	-	-	-
1977	-	-	-	-	-	-
1980	90	140	170	210	255	275
1985	150	300	390	455	590	640
1988	185	385	510	580	765	840
			Associated-Dissolved			
1974	-	-	-	-	-	-
1977	-	-	-	-	-	-
1980	675	675	675	675	675	675
1985	1,350	1,350	1,350	1,350	2,105	2,105
1988	1,350	1,350	1,350	1,350	2,350	2,350
			Total			
1974	-	-	-	-	-	-
1977	-	-	-	-	-	-
1980	765	815	845	885	930	950
1985	1,500	1,650	1,740	1,850	2,695	2,745
1988	1,535	1,735	1,860	1,930	3,115	3,190

Alaska-South

South Alaska includes all of Alaska's land area south of the Brooks Mountain Range and the continental shelf areas of the Bering Sea and the Gulf of Alaska. The development of South Alaska's offshore areas is expected to play an important part in the exploitation of Alaska's oil and gas resources within the time frame of this study. Offshore leasing in the BAU situation is scheduled to begin in the Bering Sea in 1977 with subsequent sales in the Gulf of Alaska and Cook Inlet (Table III-1). For the accelerated scenario leasing is scheduled to begin in 1975 in the Gulf of Alaska with later sales scheduled in the Gulf of Alaska and the Bering Sea and one sale scheduled to take place in Cook Inlet (Table III-3). Little additional development is projected for South Alaska's onshore areas.

As in the case of North Alaska, three projections of South Alaska non-associated gas supply were prepared manually by the Natural Gas Task Force for both the BAU and accelerated scenarios. The associated-dissolved gas supplies for South Alaska were computed by the NPC model in conjunction with the South Alaska oil projections. The basic assumptions used for preparing the South Alaska projections are discussed below.

Well Depths

The average depth of the wells to be drilled in South Alaska for gas are projected to increase from 8,600 feet in 1974 to 9,300 feet by 1988. This range is used for both the BAU and accelerated situations and is based on NPC's well depth projections.

Finding Rate

As of the beginning of 1974, according to the American Gas Association, all of Alaska's non-associated gas discoveries have been situated in South Alaska. However, no significant non-associated discoveries have been reported since 1970. At the end of 1973, South Alaska's recoverable non-associated reserves were estimated by the American Gas Association to be 5.2 trillion cubic feet.

As in the case of North Alaska it was assumed that average additions of new non-associated gas reserves would be 101 Bcf per successful well for both the BAU and accelerated situations. This is equivalent to the NPC's high finding rate for Alaska.

Success Ratio

The same success ratios used for the North Slope and the reasons for using these ratios were also utilized in preparing non-associated gas supply projections for South Alaska. A 67 percent success factor was used for the BAU cases and 50 percent for the accelerated scenarios.

Drilling Rates

Drilling rates for non-associated gas in South Alaska are projected at slightly higher levels than the North Slope which to date has been primarily an oil province. Costs for drilling the wells are expected to be high because the primary development is scheduled for hostile areas such as the Gulf of Alaska. Table IV-5 includes projected footage and number of wells for each of the six cases annually for the 1974-1988 period.

Additions to Reserves

Non-associated reserve additions as projected for South Alaska are a function of the finding rate of 101 Bcf found per successful well drilled and the number of successful wells projected for each of the six cases. In the most optimistic situation, the accelerated "high" case, cumulative non-associated additions of 23.2 Tcf were projected. This amount combined with the 14.7 Tcf for the North Slope high projection totals about 38 Tcf. This total is equivalent to approximately 10 percent of Alaska's potential gas resources as estimated by the Potential Gas Committee and the USGS. Table IV-6 lists the projected non-associated reserve additions for each of the six cases for South Alaska.

Rates of Production

During 1973 about 130 Bcf of gas was produced in South Alaska. Of this amount 118 Bcf was non-associated gas. Approximately 48 Bcf was exported to Japan as LNG with the remainder being consumed

South Alaska
Projected Non-Associated Gas Well Footage and Number of Wells Drilled
1974-1978

Year	Business As Usual Low	Business As Usual Medium	Business As Usual High	Accelerated Low	Accelerated Medium	Accelerated High
			Footage (1,000')			
1974	17	17	26	26	26	26
1975	17	17	26	26	26	26
1976	17	26	26.	130	148	157
1977	18	26	26	132	158	176
1978	79	123	150	141	176	185
1979	71	125	160	142	187	205
1980	71	134	178	151	205	225
1981	72	144	189	162	216	234
1982	63	153	207	261	351	387
1983	64	155	218	264	355	419
1984	55	182	246	264	355	419
1985	55	184	248	258	350	414
1986	46	184	248	258	350	414
1987	46	205	279	298	400	437
1988	37	205	279	307	400	446
			Wells			
1974	2	2	3	3	3	3
1975	2	2	3	3	3	3
1976	2	3	3	15	17	18
1977	2	3	3	15	18	20
1978	9	14	17	16	20	21
1979	8	14	18	16	21	23
1980	8	15	20	17	23	25
1981	8	16	21	18	24	26
1982	7	17	23	29	39	43
1983	7	17	24	29	39	46
1984	6	20	27	29	39	46
1985	6	20	27	28	38	45
1986	5	20	27	28	38	45
1987	5	22	30	32	43	47
1988	4	22	30	33	43	48

Table IV-6
South Alaska
Projected Non-Associated Reserve Additions
(Billions of Cubic Feet)

	Business As Usual			Accelerated		
Year	Low	Medium	High	Low	Medium	High
1974	135	135	203	152	152	152
1975	135	135	203	152	152	152
1976	135	203	203	758	858	909
1977	135	203	203	758	909	1,010
1978	609	947	1,150	808	1,010	1,060
1979	541	947	1,218	808	1,060	1,161
1980	541	1,015	1,353	858	1,161	1,262
1981	541	1,082	1,421	909	1,212	1,313
1982	474	1,150	1,556	1,464	1,970	2,172
1983	474	1,150	1,624	1,464	1,970	2,323
1984	406	1,353	1,827	1,464	1,970	2,323
1985	406	1,353	1,827	1,414	1,919	2,272
1986	338	1,353	1,827	1,414	1,919	2,272
1987	338	1,490	2,030	1,616	2,172	2,374
1988	271	1,490	2,030	1,666	2,172	2,424
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

ocally. Because of the mountainous terrain between South Alaska nd the lower 48 it is most likely that any gas supplies developed ill be transported to major market areas as LNG. This also ncludes any gas transported by pipeline to South Alaska from the orth Slope. Current gas production from the land area of South laska plus Cook Inlet is expected to increase nominally until the evelopment of the offshore areas begins. In the BAU situation easing of South Alaska offshore areas is scheduled to begin in 977 with drilling to follow one year later. Production from the ffshore leases is scheduled to begin in 1982. For the accelerated cenario, offshore leasing is scheduled to begin in 1975 with rilling to commence in 1976. Offshore production under this ituation is scheduled to begin in 1980.

Under the assumptions used each successful well should be apable of producing 13.8 million cubic feet per day for 20 years t a 5 percent depletion rate. The non-associated wellhead roduction was reduced 6 percent before transportation to convert he gas to a marketed basis. 1/ The following table includes pro-ected non-associated natural gas production from South Alaska or the cardinal years.

Table IV-7
South Alaska
Projected Annual Marketed Gas Production
(Billions of Cubic Feet)

	Business As Usual			Accelerated		
ears	Low	Medium	High Non-Associated	Low	Medium	High
1974	115	115	115	115	115	115
1977	125	140	140	190	210	260
1980	145	210	210	400	470	470
1985	290	440	525	750	940	1,035
1988	330	590	745	985	1,280	1,440

/ These reductions, which cover lease use, fuel use and losses, and are based on lower 48 states historical data, could prove to be conservative if significant quantities of carbon dioxide or other non-hydrocarbon gases are found with the projected non-associated reserve additions.

Table IV-8

Alaska
Projected Marketed Gas Production Summary
(Billions of Cubic Feet)

Year	BAU*	ACC*
	Non-associated	
1974	115	115
1977	140	260
1980	380	745
1985	915	1,675
1988	1,255	2,280
	Associated-Dissolved **	
1974	15	15
1977	17	19
1980	700	780
1985	1,410	1,770
1988	1,445	2,444
	Total	
1974	130	130
1977	157	279
1980	1,080	1,525
1985	2,325	3,445
1988	2,700	4,724

* High cases only.

** Includes associated-dissolved gas production projections for South Alaska which were made by the Oil Task Force.

Methane Gas Occluded In Coal

Potential Resource

It has been well publicized recently that about 260 trillion cubic feet of methane gas is contained in the remaining mapped and explored coal resources of the United States. This compares with remaining proved natural gas reserves of 250 trillion cubic feet. The estimate of methane is based on total remaining non-strippable U.S. coal resources of 1.3 trillion tons above 3,000 feet which are potentially minable by underground methods. A reasonable estimate of the methane content of such coal is 200 cubic feet of gas per ton of coal. However, the gas content of coal beds is not a criterion for establishing the production rate of wells drilled into the coal beds and USBM experts have advised that only five areas have coal reserves which may be appropriate for methane recovery in significant quantities:

Table IV-9
Remaining Coal Reserves
(Million Tons)

Eastern Kentucky	28,850
Pennsylvania	69,686
West Virginia	101,186
Virginia	9,817
Alabama	13,444
Total	222,983

Further, it is estimated that 10 to 20 percent of the methane might be retained in the coal. In view of the foregoing discussion, it is estimated that the total potential resource base of methane occluded in coal is 35 to 40 trillion cubic feet.

Projected Production

The Bureau of Mines has studied methane emissions from coal mines and has conducted investigations into the feasibility of degasifying coal beds prior to mining as a safety consideration.

There are three basic methods for recovering methane from coal beds (a) capture from active mines, (b) multipurpose borehole, and (c) mine shaft drop. Conventional wells are not generally considered adequate.

Currently there are 67 active coal mines in the U.S. which give off methane at a rate above one million cubic feet per day, and another 130 mines which emit more than 100,000 cubic feet per day, for a total of only 25 billion cubic feet per year. This gas is highly diluted with air and is at very low pressure, thus requiring expensive compression and gathering systems to make it suitable for introduction into a pipeline system. Further, many of these mines are too far from commercial pipelines to make collection practical. However, it may be practical in certain, unique situations to recover very small amounts of methane from this source.

The multipurpose borehole has been tested experimentally by the Bureau of Mines. It involves sinking about a six-foot hole to the bottom of the coal seam and drilling a number of horizontal degasification holes radially into the coal seam from an enlarged area about 14 feet in diameter at the bottom of the hole. It is termed "multipurpose" because the hole can be used as an airway, emergency manway, or power cable/communication shaft during subsequent mining operations. While the Bureau was successful in achieving an average daily production rate of 500,000 cubic feet per day, it concluded that, in view of the total cost of the hole ($848,000) measured against the potential savings of mining degasified coal ($148,000), "it is obvious that the multipurpose borehole is too costly, even if the other progressive uses of the hole are considered." However, the Bureau further concluded that if planned mine shafts were sunk by mechanical conventional method three years ahead of the time actually needed to mine the coal, these shafts could be used in conjunction with the radial drain holes to recover methane from the coal bed, and the savings from mining the degasified coal could be used to offset the interest charges related to sinking the shafts earlier than planned.

For purposes of PIB projections it has been assumed that all new underground mine shafts to be sunk in the "gassy" coal areas, and which are required to achieve the production levels projected by the PIB Coal Task Force, will be completed two years earlier than originally scheduled. It was further assumed that each shaft would produce methane at 500,000 cubic feet per day for two full years. The resulting projections are shown on Table IV-10 2/

Table IV-10
(MMcf)

	1974	1977	1980	1985	1990
Business As Usual					
NPC 10	*	3,513	4,621	6,403	6,063
NPC 9	*	3,220	4,746	7,141	7,218
NPC 6	*	297	424	591	529
Total		7,030	9,791	14,136	13,810

(Total Number of Shafts 1975 - 1989 = 537)

	1974	1977	1980	1985	1990
Accelerated Development					
NPC 10	*	10,283	14,846	23,270	34,287
NPC 9	*	10,083	15,962	24,830	35,918
NPC 6	*	933	1,425	2,214	3,231
Total		21,299	32,233	50,314	73,436

(Total Number of Shafts 1975 - 1989 = 1,973)

*Nil - Only one or two experimental holes.

Under these assumptions no significant additional investment, manpower or materials will be required over what has been projected by the Coal Task Force. However, expenditures, manpower, and materials related to shaft drops will be advanced two years over the original schedule of the Coal Task Force.

2/ The Coal Task Force made only one projection each for BAU and accelerated.

Sensitivity

The projections shown on Table IV-10 are based on a mix of 1 million and 3 million ton per year mines. Since a mine requires 8 shafts over its life regardless of size, then to the extent there are more 1 million ton mines developed than assumed, there will be more shafts required and thus more methane could be recovered. Table IV-11 shows how much methane would be recovered based on all 1 million ton mines.

Table IV-11
(MMcf)

	1974	1977	1980	1985	1990
Business As Usual	-	15,738	20,313	28,731	32,025
(Total Number of Shafts 1975 - 1989 = 1,024)					
Accelerated	-	52,704	60,939	96,624	115,473
(Total Number of Shafts 1975 - 1989 = 3,387)					

There is much more methane contained in the resource base related to the production levels projected by the Coal Task Force than could be produced from the number of shafts required to meet the Coal Task Force projections. Table IV-12 shows how much methane could be recovered if the number of shafts were not a constraint. Required shafts were computed under the assumption that one shaft could produce 500,000 cubic feet per day for two years.

Table IV-12
(MMcf)

	1974	1977	1980	1985	1990
Business As Usual	-	76,145	83,934	97,163	110,499
(Total Number of Shafts 1975 - 1989 = 3,318)					
Accelerated	-	101,025	137,566	195,983	259,431
(Total Number of Shafts 1975 - 1989 = 7,331)					

It is unlikely that under these assumptions, recovery of methane could reach the magnitude shown on Table IV-12.

Gas From the Stimulation of Tight Formations

Potential Resource

Natural gases are found in tight (low permeability), but thick and massive sand and shale deposits located predominantly (but not exclusively) in the Rocky Mountain states. A significant portion of this type of gas resource is believed to be in the Green River Basin of Wyoming, the Piceance Basin of Colorado and the Uinta Basin of Utah.

These formations require extensive fracturing if this gas is to be produced on a commercial basis. There are two different approaches, applying entirely different technology, potentially capable of creating the fracture systems necessary to make these formations capable of producing. These are:

a. Nuclear explosive fracturing, and

b. Massive hydraulic fracturing

The report of the Natural Gas Supply Technology Task Force for the National Gas Survey of the Federal Power Commission dated April 1, 1973, was used to provide basic background for this discussion, and particularly the production and cost projections.

The Natural Gas Supply Technology Task Force's estimate of the approximate gas-in-place in tight formations of the three basins was as follows:

	Trillion Cubic Feet
Green River Basin, Wyoming	240
Piceance Basin, Colorado	210
Uinta Basin, Utah	150
Total	600

The report states that these are not firm numbers and that it will take substantial drilling and testing to establish the validity of the estimates. If well stimulation processes can be effectively employed perhaps recovery could be 40 to 50 percent of this gas. Further, during the first 25 years of producing life a well was estimated to recover perhaps 18 to 38 percent of the gas-in-place in its drainage area.

Nuclear Stimulation

The Natural Gas Task Force considered nuclear explosive fracturing as not being commercially feasible within the Project Independence time frame. Nuclear stimulation experiments known as projects Gasbuggy, Rulison, and Rio Blanco have been conducted to evaluate the results of such explosions in tight gas sands. Projects Gasbuggy and Rulison utilized explosives originally designed for military purposes. Project Rio Blanco used nuclear explosives specifically designed for nuclear stimulation and with low residual radiation effects. Three separate explosives were fired simultaneously at different depths in a single well bore during May 1973. When the well was re-entered, tests indicated that tapping the top "Chimney" resulting from the top explosive, did not establish communication with the entire stimulated zone. 3/ During the latter part of June 1974 the drilling of an additional well was commenced. This well is to be sidetracked to enter the middle cavity. The generally unfavorable public reaction as to possible environmental and safety hazards associated with nuclear stimulation is a major constraint in the use of nuclear fracturing. Evaluations of nuclear blasts on a case-by-case basis may show relatively low environmental effect. However, when assessed by the ramifications within the total system, a different picture might emerge.

The position of using only projections resulting from massive hydraulic fracturing is strengthened by reason that the same common gas resource base is currently being considered

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3/ "Rio Blanco Production Testing Terminated; New Try Pondered," Nuclear Industry, March 1974, pp. 34-36.

for development. Therefore, if the selection of the type of tight sand stimulation is not accurate,the results in reserves made available can still be considered plausible. Also, there is a possibility that nuclear stimulation of natural gas wells might be an inefficient use of nuclear materials that could best be used for electric power generation. Part of the answer to this problem is involved in the success of nuclear fracturing relative to the success of massive hydraulic fracturing of tight gas sands and the comparative costs of each.

Massive Hydraulic Fracturing

Hydraulic fracturing has been successfully used for a number of decades to increase oil and gas recovery. However, the use of the technique on the deeper formations with very low permeability and porosity, and on the type of sands found in the Rocky Mountain Basins where massive hydraulic fracturing is contemplated must be tested on a full-scale basis in these basins. It will take such specific applications and testing to demonstrate that adequate and sustained gas productivity can be achieved to economically produce gas from these tight formations. The fracture creation and proppant placement to keep these fractures open could be successful but there is a question whether the in-place permeability and sand continuity are adequate to allow the gas to move through the rock and enter the fracture systems.

A joint venture of private industry and the Federal Government to test massive hydraulic fracturing in the tight sands of the Northwest Colorado Piceance Basin is in progress. 4/ The test well has been commenced less than a mile from the Rio Blanco nuclear stimulation site. The Atomic Energy Commission and the U.S. Bureau of Mines have jointly authorized approximately $1 million for the project and the remaining portion of the total costs of $2.5 million are to be furnished by an industry group.

4/ "Big Rio Blanco Frac Job Near" Oil and Gas Journal, May 27, 1974, pp. 33.

Also, El Paso Natural Gas Company has plans to undertake a research and development program designed to determine the feasibility of new techniques in hydraulic fracturing of low permeability gas bearing formations in the Green River Basin of Sublette Co., Wyoming. El Paso estimated expenditures totaling up to $7,585,000 for the two well proposed program. 5/ The filing requests prior Commission approval for the proposed accounting treatment for expenditures made in connection with the experimental hydraulic fracturing program and for inclusion of such expenditures in El Paso's cost of service in future rate proceedings. 6/

Availability of fracing fluids was not considered a limiting feature of successful massive hydraulic fracturing programs in the areas contemplated. These fluids might contain water, condensate, and/or oil and would be treated to result in the characteristics necessary for an efficient fracturing fluid of sufficient viscosity to carry the proppant. Further, these fluids must have a low viscosity following the treatment so that they can be produced from the wells after treatment. Therefore, a major percentage of these fluids would be returned to the surface, be placed in storage, and would be available for use in subsequent treatments. Any water produced from the water element of the fracturing fluids would contain dissolved salts. The cost of these fluids and the difficulty of the disposal of the water portion would make the reuse of these fluids most logical.

Basis For Development Of Projections

The Natural Gas Task Force develops a "High Production Case" and a "Low Production Case" as order-of-magnitude type of estimates. The high case incorporates a high development rate with more favorable reservoir conditions. The low case assumes development rates about 50 percent lower and less favorable reservoir

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5/ El Paso Natural Gas Co. filed 3-13-74 "Proposed Accounting and Rate Treatment for Research and Development Expenditure Associated with an Experimental Hydraulic Fracturing Program." Noticed 3-28-74, in Docket No. RP74-74.

6/ Order No. 483 issued April 30, 1973, and Order Denying Rehearing of Order No. 483, issued June 28, 1973, at Docket R-462; Research and Development Accounting and Reporting.

conditions. It is yet to be demonstrated that massive hydraulic fracturing can practically or economically achieve the levels of gas supply of either of the cases developed. This resulted in using production and cost figures developed as follows for massive fracturing:

Case	Natural Gas Techology Task Force Projections Used
Accelerated	
High	Fifty percent of High Production Case
Medium	Fifty percent of Low Production Case
Low	Fifty percent of Low Production Case (Piceance and Uinta Basins only)
Business as Usual	
High	Fifty percent of Low Production Case (Uinta Basin Only)
Medium	No commercial production
Low	No commercial production

These projections take into consideration in a judgmental manner the Natural Gas Techology Task Force's study as it evaluated massive hydraulic fracturing. The "Categories of Confidence" assigned to the natural gas resource base in the three Rocky Mountain Basins were noted. Wellhead costs developed showed the Uinta Basin to be the source of the lowest cost gas. This influenced retaining the Uinta Basin in the High "Business as Usual" scenario.

Table IV-13

Massive Hydraulic Fracturing
Summary of Production Projections
Trillions of Cubic Feet

Case and NPC Region		Target Year 1974	1977	1980	1985	1988
				Business As Usual		
Low		No commercial production projected				
Medium		No commercial production projected				
High	No. 3	0.0	0.0	0.1	0.2	0.3
	No. 4	0.0	0.0	0.0	0.0	0.0
	Total	0.0	0.0	0.1	0.2	0.3
				Accelerated		
Low	No. 3	0.0	0.0	0.1	0.4	0.5
	No. 4	0.0	0.0	0.0	0.0	0.0
	Total					
Medium	No. 3	0.0	0.0	0.1	0.4	0.5
	No. 4	0.0	0.0	0.1	0.3	0.3
		0.	0.1 */	0.3 */	0.6 */	0.8
High	No. 3	0.0	0.2	0.8	1.5	1.7
	No. 4	0.0	0.0	0.3	0.5	0.6
	Total	0.0	0.2	1.1	2.0	2.3

*/ Does not add due to rounding

V. COSTING AND RESOURCE REQUIREMENTS ASSUMPTIONS AND PROCEDURES

Updating and Projection of Costs

The NPC's *Oil and Gas Availability Study* projected cost parameters for the 1971 to 1985 period based on 1970 data. A complete description of their methodology and assumptions is provided in NPC, *U.S. Energy Outlook, Oil and Gas Availability, 1973*, pp. 615-724.

The Natural Gas Task Force updated the NPC's gas cost data base from 1970 to 1972/73 and projected cost parameters through 1990, expressed in 1973 constant dollars. The primary data sources for the cost updating were the 1972 *Joint Association Survey of the U.S. Oil and Gas Producing Industry* and private industry surveys.

The parameters were developed with the specific intent of providing values for calculating investments and expenses for a variety of industry drilling activities. Therefore, many of the parameters are a function of drilling costs (whih (which include the cost of successful wells, offshore substructures, and dry holes). In general, the projected ratios were an extrapolation of historical trends.

Projections were made for the following costing factors:

1. Exploration and Production Overhead
2. Royalty Rate
3. Lease Rental Costs
4. Lease Equipment Costs
5. Geological and Geophysical Costs
6. Offshore Lease Acquisition Costs
7. Ad Valorem and Production Taxes
8. Operating Costs
9. Onshore Lease Acquisition Costs
10. Drilling Costs (Gas & Dry)

The following sections describe in detail the development of projections for each of these factors.

Exploration and Production Overhead

Exploration and production overhead costs were derived as a function of drilling and producing costs as follows:

$$\text{Projected Ratio} = 0.179 = \frac{\text{Annual Overhead Costs}}{\text{Annual Drilling and Producing Costs}}$$

These overhead costs were allocated between existing and new wells as follows:

A = Annual Drilling Costs + Producing Costs New Wells + Producing Costs Old Wells

<u>New Wells</u>

$$\text{Total Overhead, New Wells} = 0.179 * A * \left(\frac{\text{No. of new wells}}{\text{No. of New wells + no. of existing wells}}\right)$$

<u>Existing Wells</u> - (year equivalent to above year 0)

$$\text{Total Overhead, Old wells} = 0.179 * A * \frac{\text{Existing Wells}}{\text{No. of new wells + No. of Existing wells}}$$

Data for the parameters of the overhead ratios were obtained from the <u>Joint Association Survey of the U.S. Oil and Gas Producing Industry</u>. Data were available through 1972.

Exploration and production costs are obtained from Table 1, page 76, item 4.d., <u>1972 Joint Association Survey of the U.S. Oil and Gas Producing Industry</u> as follows:

1) Drilling and Equipment Exploratory Wells, item 1.a.
2) Contributions toward Test Wells, item 1.e.
3) Drilling & Equipping Development Wells, item 2.a.
4) Production Expenditures Including Overhead, item 3.a.

The data are presented in Table V-1.

A constant ratio of 0.179 was obtained in 1971 and 1972 and this ratio has been used for the projections.

TABLE V-1

EXPLORATION AND PRODUCTION OVERHEAD

(MILLION DOLLARS PER YEAR) (1)

YEAR	OVERHEAD	DRILLING AND PRODUCING COSTS	RATIO
1959	625	4,101	0.152
1960	621	3,815	0.163
1961	676	3,853	0.175
1962	691	4,111	0.168
1963	670	3,883	0.173
1964	676	4,041	0.167
1965	694	4,087	0.170
1966	673	4,255	0.158
1967	701	4,232	0.166
1968	743	4,503	0.165
1969	786	4,800	0.164
1970	825	4,958	0.166
1971	873	4,876	0.179
1972	963	5,377	0.179
Projected			0.162

(1) All values in current dollars

Source: Joint Association Survey

Royalty Rate

Royalty rate as used herein is the fraction of gross revenue that goes outside the industry. The historical data, as shown in Table V-2 have been calculated assuming a 15 percent royalty rate per the Joint Association Survey of the U.S. Oil & Gas Producing Industry. The 0.15 assumed royalty rate is reduced to 0.13, as some royalty type payments are retained by the Oil and Gas Industry. In view of the general applicability of a one-eighth royalty rate in onshore areas and the previous analysis, a rate of one-eighth was used for onshore regions in both scenarios.

In recent years, Federal and State lands plus some non-government controlled lands have been leased for 0.167 (one-sixth) royalty rates. This has been particularly true of the Federal offshore, although the statutory minimum rate is one-eighth. One-sixth royalty was used by the Task Force in the Business As Usual scenario and one-eighth royalty was used in the Accelerated Development scenario, representing a change in government policy.

Lease Rental Costs

Lease rental costs were derived as a function of drilling costs as follows:

$$\text{Ratio} = 0.055 = \frac{(\text{Annual Lease Rental Costs})}{(\text{Annual Drilling Costs})}$$

Lease rental costs were allocated between existing wells and new wells as follows:

B = Annual Drilling Costs

<u>New Wells - Year 0</u>

$$\text{Total Rental Costs} = B * 0.055 * \left(\frac{\text{new wells}}{\text{new wells + existing wells}}\right)$$

<u>Existing wells - (Year equivalent to Year 0)</u>

$$\text{Total Rental Costs} = B * 0.055 * \left(\frac{\text{existing wells}}{\text{new wells + existing wells}}\right)$$

<u>Other years</u>

Proportion between wells after year 0 based on well count; i.e., $0.055 * B * \frac{(\text{No of wells})}{(\text{Total Wells})}$

TABLE V-2

ROYALTY RATE (1)

Year Historical	Net Revenue	Gross Revenue (2)	Total Receipts (3)	Royalty Rate Fraction
1959	7,676	9,031	----	----
1960	7,829	9,211	8,062	.1247
1961	8,128	9,562	8,372	.1245
1962	8,431	9,919	8,685	.1244
1963	8,750	10,294	9,029	.1229
1964	8,844	10,405	9,136	.1220
1965	9,055	10,653	9,327	.1245
1966	9,715	11,429	9,999	.1251
1967	10,433	12,274	10,743	.1247
1968	11,019	12,964	11,328	.1262
1969	11,800	13,882	12,129	.1263
1970	12,681	14,919	13,005	.1283
1971	13,421	15,789	13,747	.1293
1972	13,509	15,893	13,830	.1298
Projection Onshore				.1250
Projection Offshore				.1666

(1) Royalty that goes outside the industry.

(2) Calculated from net revenue assuming 15 percent royalty per Joint Association Survey.

(3) Reported by Joint Association Survey as net revenue plus revenue from royalties.

Source: Joint Association Survey

A constant ratio was projected. Data for the parameters were obtained from the Joint Association Survey of the U.S. Oil & Gas Producing Industry. Data were available through 1972.

Lease rental costs entitled, "Lease Rentals and Exp. for Carrying Leases," are Item 1.c., Table 1, Section II, page 76, 1972 Joint Association Survey of the U.S. Oil & Gas Producing Industry.

The data are presented in Table V-3.

This ratio has decreased slightly over the past few years. It is believed that the recent increases in rental costs and drilling costs will result in a constant ratio in the future. A projection of the data in 1971 and 1972, 0.045, was used.

These lease rental costs were projected by the Task Force for use in sensitivity analysis, and were not included in the basic Business As Usual and Accelerated Development scenario cases since to do so would preclude treatment of economic rents (the difference between market clearing price and "minimum acceptable price" multiplied by number of units sold) in the integrating effort. Such treatment constituted one of the important policy analysis objectives of Project Independence Blueprint's Integrating effort.

Lease Equipment Costs

Lease equipment costs were derived as a function of Drilling and Equipment Producing Well Expenditures.

$$\text{Ratio} = 0.200 = \frac{\text{Annual Lease Equipment Costs}}{\text{Annual Drilling and Equipment Producing Well Expenditures}}$$

Lease equipment costs were allocated between existing wells and new wells as follows:

C = Annual Drilling and Equipment Producing Well Expenditures

New Wells - Year 0

Total Lease Equipment New Wells = 0.75 * 0.267 * C

Existing Wells - (year equivalent to above year 0)

Total Lease Equipment Existing Wells = .25 X 0.267 X C

TABLE V-3

LEASE RENTAL COSTS

(MILLION DOLLARS PER YEAR) (1)

YEAR	LEASE RENTALS	DRILLING COSTS	RATIO
1959	193	2,651	0.073
1960	193	2,425	0.080
1961	189	2,398	0.079
1962	197	2,576	0.076
1963	193	2,302	0.084
1964	177	2,428	0.073
1965	166	2,402	0.069
1966	180	2,360	0.076
1967	140	2,299	0.061
1968	179	2,409	0.074
1969	134	2,611	0.051
1970	138	2,579	0.054
1971	143	2,372	0.060
1972	142	2,814	0.050
Projected			0.045

(1) All values in current dollars.

Source: Joint Association Survey

A constant ratio was projected. Data for the parameters were obtained from the Joint Association Survey of the U.S. Oil & Gas Producing Industry. Data were available through 1972.

Lease Equipment costs entitled, "Lease Equipment," are Item 2.b., Table 1, Section II, Page 76, 1972 Joint Association Survey of the U.S. Oil & Gas Producing Industry.

Drilling and equipment of producing wells expenditures are the sum of the oil well plus the gas well expenditures for the total United States, Table 1, Section 1, Page 7, 1972 Joint Association Survey of the U.S. Oil & Gas Producing Industry.

The data are presented in Table V-4. This ratio has been reasonably constant in recent years. The projected ratio was assumed to be the same for both oil wells and gas wells.

Geological and Geophysical Costs

Geological and Geophysical costs were derived as a function of drilling and producing costs.

$$\text{Ratio} = 0.084 = \frac{\text{Annual Geological and Geophysical Costs}}{\text{Annual Drilling and Producing Costs}}$$

Geological and Geophysical costs should be allocated between existing wells and new wells as follows:

D = Annual Drilling Costs + Producing Costs New Wells + Producing Costs Old Wells

New Wells - Year 0

Total G & G New Wells = 0.25 * D * 0.112

Existing Wells - (year equivalent to above year 0)

Total G & G Existing Wells = 0.75 * D * 0.112

A constant ratio was projected. Data for the parameters were obtained from the Joint Association Survey of U.S. Oil and Gas Producing Industry. Data were available through 1972.

Geological and geophysical costs include the following:

1) Geological and Geophysical (1.d.)
2) Other Inc., Direct Overhead (1.g.)
3) Land Dept., Leasing, & Scouting (1.f.)

Drilling and producing costs include the following:

TABLE V-4

LEASE EQUIPMENT COSTS
(MILLION DOLLARS) (1)

YEAR	TOTAL LEASE EQUIPMENT EXPENDITURE (2)	IMPROVED RECOVERY EQUIPMENT EXPENDITURE (3)	PRIMARY LEASE EQUIPMENT EXPENDITURE	DRILLING AND EQUIPMENT PRODUCING WELLS EXPENDITURES	RATIO OF PRIMARY LEASE EQUIPMENT TO PRODUCTIVE WELL COST FRACTION
1959	483	----	483	1,830	.264
1960	431	----	431	1,651	.261
1961	446	----	446	1,624	.275
1962	537	40	497	1,729	.287
1963	527	80	447	1,512	.296
1964	619	115	504	1,574	.320
1965	580	150	430	1,553	.277
1966	646	187	459	1,528	.300
1967	675	247	428	1,497	.286
1968	606	222	384	1,583	.243
1969	745	303	442	1,723	.257
1970	728	285	443	1,705	.260
1971	711	323	388	1,507	.257
1972	807	310	497	1,808	.275
Projected					.200

(1) All values in current dollars.
(2) Reported by Joint Association Survey as "Equipment Leases" through 1965; for 1966 and future years, equal to the sum of lease equipment and improved recovery equipment.
(3) As reported by Joint Association Survey in 1966 and future years. Prior to 1968, values attained by extrapolation of 1966-1970 data.

Source: Joint Association Survey.
Note: In this study the same fraction was used for both oil wells and gas wells.

1) Drilling and Equipping Exploratory Wells (1.e.)
2) Contributions Toward Test Wells (1.e)
3) Drilling and Equipping Development Wells (2.a.)
4) Production Expenditures Including Direct Overhead (3.a.)

The above numerals and letters within brackets, example (1.a.), refer to Table 1, Section II, Page 76, 1972 Joint Association Survey of the U.S. Oil & Gas Producing Industry. The exploration direct overhead (Item 1.g.) included above was not a portion of the more general overhead category entitled, "Exploration and Production Overhead," in a previous study by the National Petroleum Council, U.S. Energy Outlook Oil and Gas Availability, published in 1973. Thus, it appears appropriate to include this item with the geological and geophysical costs.

The data are presented in Table V-5.

A decreasing trend of the ratio is observed between 1967 and 1972. A slight decrease from the 1972 ratio to 0.112 was projected. This value was used as a constant in the projections. It is anticipated that recent increases in personnel and geophysical activity should prevent a further decline of the ratio.

Offshore Lease Acquisition Costs

Offshore lease acquisition costs are expressed in dollars per acre leased.

Historical data from October, 1954, through March, 1974, are presented on Table V-6. Average values for approximate five-year periods have been calculated and are presented in Table V-7.

A projected cost has been prepared based on the recent five-year average data. A lease acquisition cost of $3,400 per acre was projected for leases which are in prospective oil areas, and a lease acquisition cost of $2,500 per acre was projected for leases which are in prospective gas areas.

These lease acquisition costs were projected by the Task Force for use in sensitivity analysis, and were not included in the basic Business As Usual and Accelerated Development scenario cases, since to do so would preclude treatment of economic rents (the difference between market clearing price and "minimum acceptable price" multiplied by number of units sold) in the integrating effort. Such treatment constituted one of the important policy analysis objectives of Project Independence Blueprint's integrating effort.

TABLE V-5

GEOLOGICAL AND GEOPHYSICAL COSTS
(MILLION DOLLARS PER YEAR) (1)

YEAR	GEOLOGICAL AND GEOPHYSICAL	EXPLORATION DIRECT OVERHEAD	LAND LEASE AND SCOUTING	TOTAL	DRY HOLES	DRILL & EQUIP PRODUCING WELLS	PRODUCING COSTS	TOTAL	RATIO
1964	336	72	100	508	854	1,574	1,613	4,041	0.125
1965	355	61	102	518	849	1,553	1,685	4,087	0.127
1966	378	128	70	576	832	1,528	1,895	4,255	0.133
1967	392	122	86	600	802	1,497	1,933	4,232	0.142
1968	373	136	82	591	826	1,583	2,094	4,503	0.133
1969	387	168	93	648	888	1,723	2,189	4,800	0.135
1970	349	143	98	590	873	1,706	2,379	4,958	0.199
1971	361	142	100	603	864	1,508	2,504	4,876	0.124
1972 Projected	372	147	105	624	1,006	1,808	2,563	5,377	0.084

(1) All values in current dollars.

Source: Joint Association Survey.

TABLE V-6

LEASE ACQUISITION COSTS - OFFSHORE OUTER CONTINENTAL SHELF
OIL AND GAS LEASE SALES

Date of Sale	Location	Tracts Offered	Acres Offered (000)	Tracts Leased	Acres Leased (000)	Total Bonus ($000,000)	Avg. Bonus Per Acre ($)	Acreage Leased Percent
10/54	Louisiana	199	748.0	90	394.7	116.38	295	53
11/54	Texas	38	117.8	19	67.1	23.36	3481	57
7/55	Texas	39	216.0	27	149.8	8.44	56	69
7/55	Louisiana	171	458.1	94	252.8	100.09	396	55
5/59	Florida	80	458.0	23	132.5	1.71	13	29
8/59	Louisiana	38	81.8	19	38.8	88.04	2,269	47
Subtotal		565	2,079.7	272	1,035.7	338.02	326	50
2/60	Texas	97	437.8	48	240.5	35.73	149	55
2/60	Louisiana	288	1,137.2	99	464.0	246.91	532	41
3/62	Louisiana	401	1,808.3	206	951.8	177.26	186	53
3/62	Texas	30	90.7	10	28.8	.56	19	32
3/62	Louisiana	380	1,780.3	195	927.7	267.78	289	52
10/62	Louisiana	19	33.9	9	16.2	43.89	2,709	48
5/63	California	129	669.8	57	312.9	12.81	41	47
4/64	Louisiana	28	34.0	23	32.7	60.34	1,845	96
10/64	Oregon	149	836.1	74	425.4	27.77	65	50
10/64	Washington	47	253.9	27	155.4	7.76	50	61
Subtotal		1,568	7,082.0	748	3,555.4	880.81	248	50
3/66	Louisiana	18	36.0	17	35.1	88.85	2,531	98
10/66	Louisiana	52	227.9	24	104.7	99.16	947	46
12/66	California	1	2.0	1	2.0	21.19	10,595	100
6/67	Louisiana	206	971.5	158	744.5	510.08	685	77
2/68	California	110	540.6	71	363.2	602.72	1,659	67
5/68	Texas	169	728.6	110	541.3	593.90	1,097	74
11/68	Louisiana	26	46.8	16	29.7	149.87	5,046	63
1/69	Louisiana	38	96.4	20	48.5	44.04	908	50
12/69	Louisiana	27	93.8	16	60.2	66.91	1,111	64
Subtotal		647	2,743.6	433	1,929.2	2,176.72	1,128	67
7/70	Louisiana	34	73.4	19	44.6	97.77	2,192	61
12/70	Louisiana	127	593.5	118	551.4	846.78	1,536	93
11/71	Louisiana	18	55.9	11	37.2	96.30	2,587	67
9/72	Louisiana	78	366.7	62	290.3	585.83	2,018	78
12/72	Louisiana	132	604.0	116	535.9	1,665.52	3,108	88
6/73	Tex-La	129	697.6	100	547.2	1,591.40	2,908	78
12/73	Miss-La-Fla	147	812.3	87	485.4	1,491.07	3,072	59
3/74	Louisiana	206	928.8	91	421.2	2,092.51	4,968	45
Subtotal		871	4,132.2	604	2,913.2	8,467.18	2,906	70

TABLE V-7

Average Offshore Lease Acquisition Cost
Dollars Per Acre

Interval	Average Cost Per Acre, $
1955-1960	300
1960-1965	250
1965-1970	1,150
1970-1973	2,900
Projected	
Gas	2,500
Oil	3,400

Ad Valorem and Production Taxes

Ad valorem and production tax expenditures are expressed as a percentage applied to total receipts from gas income. Total receipts are defined as income from gas production after deduction of royalty payments.

The largest component of this quantity is the production (or severance) tax. Both it and the ad valorem tax vary considerably by state and in the case of ad valorem tax by smaller units including counties and school districts. The values of these taxes for some representative important producing states are given in Table V-8. On a national basis, the ad valorem and production tax history is presented in Table V-9.

Due to the geographic variation in rates, the figures used for these taxes in this study were arrived at by addition of an average ad valorem tax to the statutory severance or production tax on a state by state basis. The resulting values were then combined as a weighted average into values for the NPC regions. These values are reported in Table V-10.

Operating Costs

Operating costs for gas wells are expressed as a function of dollars per year per well. A separate cost estimate was prepared for gas wells in each National Petroleum Council Region.

Historical operating cost data are available as a total cost per year to operate all oil and gas wells in the United States (Item 3.a., Table 1, Section II, Page 76 of the <u>1972 Joint Association Survey of the U.S. Oil & Gas Producing Industry</u>.

TABLE V-8

AD VALOREM AND PRODUCTION TAXES

State	Estimated Ad Valorem Tax Rate Fraction of Income	Production or Severance Taxes	Estimated Total Tax Rate Fraction of Income
Oil			
Texas	0.25 to 0.86	4.66% of value + 0.001875 $ per barrel	.082
Louisiana	Usually none	12.5% of value with exceptions	.120
California	.070 to 1.00	Varies by counties	.080
Oklahoma	None	7.0% of value + $0.0022 $ per barrel	.070
Wyoming	Approx. .075	0.53% of value	.080
New Mexico	Approx. .04	Approx. 4.0% of value	.080
GAS			
Texas	.025 to .086	7.5% of value	.110
Louisiana	Usually none	$.03 to $.07 per Mcf	.200
Oklahoma	None	7.0% of value, + $0.0002 $ per Mcf	.070
New Mexico	Approx. .040	Approx. 3.0% of value	.070
Kansas	.060	$0.00025 per Mcf	.060
California	.070 - .100	Varies by counties	.080
Wyoming	Approx. .075	0.53% of value	.080

Source: LaRue, Moore and Associates

TABLE V-9

AD VALOREM AND PRODUCTION TAXES

(MILLION DOLLARS) (1)

History	Ad Valorem and Production Taxes	Net Revenue	Royalty Payments Received	Total Receipts (2)	Tax Rate (Fraction)
1959	508	7,676	-	7,676	.0662
1960	538	7,829	233	8,062	.0667
1961	541	8,128	244	8,372	.0646
1962	556	8,431	254	8,685	.0640
1963	571	8,750	279	9,029	.0632
1964	597	8,844	292	9,136	.0653
1965	612	9,055	272	9,327	.0656
1966	642	9,715	284	9,999	.0642
1967	712	10,433	310	10,743	.0663
1968	758	11,019	309	11,328	.0669
1969	796	11,800	329	12,120	.0656
1970	857	12,681	324	13,005	.0659
1971	882	13,421	326	13,804	.0639
1972	882	13,509	321	13,883	.0635

(1) All values in current dollars.

(2) Excludes income from other than oil and gas.

Source: Joint Association Survey.

Note: The Projected tax rates are based on a composite representative sample of several important states.

Table V-10

GAS AD VALOREM AND PRODUCTION TAX RATES

NPC Region	Combined Rate
2	8.00 %
2A	0.00 %
3	7.04 %
4	7.91 %
5	10.55 %
6	13.77 %
6A	0.00 %
7	8.25 %
8 and 9	7.29 %
10	7.29 %
11	7.00 %
11A	0.00 %

Data are not available to divide the total cost per year into costs for oil wells and for gas wells. Similarly, data are not available to proportion the costs to the various National Petroleum Council Regions.

Operating costs for oil wells and gas wells were developed by NPC regions in a previous study of the National Petroleum Council. This previous work utilized an industry survey to aid in proportioning costs between the various regions. These costs were adjusted to equal the total cost as presented in the Joint Association Survey of the U.S. Oil & Gas Producing Industry. Total operating costs were split 78 percent to oil and 22 percent to gas (p. 617 and 618, National Petroleum Council, U.S. Energy Outlook, Oil and Gas Availability, published in 1973.)

These gas well operating costs were used as a point of reference from which the operating cost data were developed. An investigation of the recent total operating cost data indicates an increase of approximately 25 percent is generally applicable. The annual operating costs, number of producing wells, and the average cost per well are presented in Table V-11, from which the increase was derived. The 25 percent increase was used for all regions.

Annual statistics indicate that the average depth of wells completed each year has increased significantly. Since operating costs for existing wells include many older shallow wells, it is appropriate that the operating costs for new wells should be higher than assigned for existing wells. As a result of a review of recent industry data concerning costs and average completed oil well depths, the operating costs developed in the National Petroleum Council, U.S. Energy Outlook, Oil and Gas Availability published in 1973, were increased 24 percent to determine the operating costs for new gas wells, Table V-12. Exceptions to this increase were Alaska, the offshore regions, and Region 6 (Gulf Coast Onshore). Data for these exceptions were obtained from recent industry data.

Since annual statistics indicate that the average depth of gas wells completed each year has not been increasing significantly, the same data for operating costs of gas wells was used for existing and new well.

TABLE V-11

OPERATING COSTS

Year	Operating Costs Dollars (1)	Producing Oil Wells (2)	Producing Gas Wells (2)	Average Operating Cost, Dollars Per Year Per Well
1968	2,094,000	548,331	123,528	3,117
1969	2,189,000	537,640	125,020	3,303
1970	2,379,000	517,177	118,864	3,740
1971	2,504,000	512,471	117,300	3,976
1972	2,563,000	503,505	119,167	4,116
1973				

(1) Item 3a, Table 1, Section II, page 76, 1972 Joint Association Survey of the U.S. Oil & Gas Producing Industry.

(2) Source: World Oil.

TABLE V-12

OPERATING COSTS

GAS WELLS

Region	Operating Costs, Existing Wells And New Wells Dollars per Year
1N	60,000
1S	60,000
2	4,500
2A	50,000
3	6,375
4	7,625
5	12,062
6	12,200
6A	50,000
7	5,625
8	1,250
9	1,250
10	1,250
11	7,625
11A	50,000

Onshore Lease Acquisition Costs

Onshore lease acquisition costs are expressed as a function of onshore drilling expenditures as follows:

$$\text{Projected Ratio} = 0.080 = \frac{\text{Onshore Lease Acquisition}}{\text{Onshore Drilling Expenditures}}$$

A projected ratio of 0.138 was obtained in a previous study by the National Petroleum Council, U.S. Energy Outlook, Oil and Gas Availability published in 1973. This work included data through 1969. The onshore lease acquisition costs were obtained from the Chase Manhattan Bank industry Cost Studies. The onshore drilling expenditures were obtained from the Joint Association Survey of the U.S. Oil & Gas Producing Industry.

The historical data published by the Chase Manhattan Bank and the Joint Association Survey of the U.S. Oil & Gas Producing Industry were investigated. Using the Chase Manhattan Bank Cost Studies, it was not possible to duplicate the data published in the abovementioned National Petroleum Council Study. For the Joint Association Survey data, it was found that the total United States Lease Acquisition Expenditures (item 1.b., Table 1, Section II, page 76, 1972 Joint Association Survey of the U.S. Oil and Gas Producing Industry)were less than the Offshore Lease Expenditures for two years. Since these discrepancies could not be properly resolved, a projected ratio of 0.080 was used. Recent trends do indicate that lease acquisition costs will increase; coupled with increased drilling expenditures this should result in a constant ratio. The data are presented on Table V-13. Onshore Drilling Expenditures through 1969 are from the National Petroleum Council, U.S. Energy Outlook, Oil and Gas Availability, published in 1973, Table 598, Page 669, The more recent onshore drilling expenditures are from the Joint Association Survey of the U.S. Oil & Gas Producing Industry (Table 1, Section,1, page 7) and represent total U.S. drilling costs less the offshore costs for Texas, Louisiana, California and Alaska.

These lease acquisition costs were projected by the Task Force for use in sensitivity analysis, and were not included in the basic Business As Usual and Accelerated Development scenario cases, since to do so would preclude treatment of economic rents (the difference between market clearing price and "minimum acceptable price" multiplied by number of units sold) in the integrating effort. Such treatment constituted

TABLE V-13

LEASE ACQUISITION COSTS - ONSHORE

(MILLION DOLLARS PER YEAR) (1)

	(2)			(3)					(4)		
YEAR	ONSHORE LEASE ACQUIS-ITIONS	ONSHORE DRILLING EXPEND-ITURES	RATIO	TOTAL U.S. LEASE ACQUIS-ITIONS	OFFSHORE & ALASKA LEASE ACQUIS-ITIONS	ONSHORE LEASE ACQUIS-ITIONS	ONSHORE DRILLING EXPEND-ITURES	RATIO	TOTAL U.S. LEASE ACQUIS-ITIONS	ONSHORE LEASE ACQUIS-ITIONS	RATIO
1959	311	2,469	0.126								
1960	310	2,216	0.140								
1961	305	2,167	0.140								
1962	229	2,305	0.099								
1963	338	2,012	0.168								
1964	394	2,069	0.190	---	96	---	2,069	---	570	474	0.229
1965	339	1,974	0.172	500	11	489	1,974	2.248	438	427	0.216
1966	228	1,830	0.124	560	209	351	1,830	0.192	577	368	0.201
1967	202	1,685	0.120	860	510	350	1,685	0.208	829	319	0.189
1968	216	1,742	0.124	---	1,346	---	1,742	---	1,578	232	0.133
1969	215	1,945	0.110	1,250	1,011	239	1,945	0.123	1,137	126	0.065
1970				1,100	945	155	1,980	0.078	714	-231	?
1971				300	96	204	1,876	0.109	642	546	0.291
1972				---	2,251	---	2,182	---	1,722	-69	?
Projected								0.080			

(1) All values in current dollars

(2) Table 598, page 669, U.S. Energy Outlook, Oil & Gaś Availability, National Petroleum Council, published 1973.

(3) Total United States Lease Acquisitions from Chase Manhattan Bank Industry Cost Studies

(4) Total United States Lease Acquisitions from Joint Association Survey of the U.S. Oil & Gas Producing Industry.

one of the important policy analysis objectives of Project Independence Blueprint's integrating effort.

Drilling Costs (Oil, Gas, & Dry)

Drilling cost information was developed from the Joint Association Survey of the U.S. Oil & Gas Producing Industry for the year 1972, the latest year available. For each of the major oil and gas producing states, the JAS shows the number of wells drilled, the total footage drilled and the total cost separately for oil wells, gas wells and dry holes in 1,250-foot depth increments down to 5,000 feet and 2,500-foot increments from 5,000 feet to maximum depth. The wells, footage and costs were accumulated by NPC regions, and the average depth-cost per foot relationship for wells in each depth bracket for each NPC region was determined for oil wells, gas wells and dry holes (Table V-14).

It was determined that a plot of the logarithm of drilling cost as a function of depth provided the most consistent linear relationship. However, the average cost per foot for all wells is not equal to the cost per foot at the average of the deeper wells. To adjust for this difference, both the cost per foot at the average depth for all wells and the average cost per foot as calculated from total drilling costs and total feet drilled was determined. The difference between the two was used to adjust the drilling cost for a particular depth as determined from the plots.

Drilling costs were adjusted for cost increases since 1972 by applying a cost index factor of 1.309 to the cost per foot determined from 1972 data. The cost index was obtained by using data from the IPAA Index of Drilling and Equipping Wells developed for 1972 and 1973 by the Cost Study Committee of the Independent Petroleum Association of America. Cost Increases were obtained from a survey of key industry personnel and suppliers and the resulting information applied to the prior index. These data indicate that overall drilling costs have increased approximately 30.9 percent since 1972.

Gas Operations Costing Procedures for NPC Model Generated Production

Annual Costs

All of the cash expenditures were derived from estimates of drilling expenditures and the number of wells as estimated by the NPC gas exploration and reserve development program sections. The calculations consist of ratios multiplied by drilling expenditures or number of wells (e.g., geological geophysical expenditures equal drilling expenditures times .084).

TABLE V-14

AVERAGE DRILLING COSTS BY REGION

FOR ALL WELLS IN EACH TYPE (1)

	TYPE WELL	AVERAGE DEPTH (FEET)	AVERAGE DRILLING COST ($/foot)
Region 1	Oil	10,801	131.25
	Gas	9,291	285.64
	Dry Holes	8,196	235.57
Region 2	Oil	2,486	26.31
	Gas	5,930	24.96
	Dry Holes	5,769	17.19
Region 2A	Oil	5,258	53.77
	Gas	-	-
	Dry Holes	6,453	52.00
Region 3	Oil	8,113	44.87
	Gas	4,230	18.58
	Dry Holes	5,317	9.77
Region 5	Oil	4,755	13.75
	Gas	7,881	34.18
	Dry Holes	4,616	12.83
Region 6	Oil	5,600	21.71
	Gas	6,895	27.71
	Dry Holes	7,515	17.08

TABLE V-14 (cont'd.)

AVERAGE DRILLING COSTS BY REGION

FOR ALL WELLS IN EACH TYPE (1) (CONT'D.)

	TYPE WELL	AVERAGE DEPTH (Feet)	AVERAGE DRILLING COST ($/Foot)
Region 6A	Oil	10,484	64.79
	Gas	10,698	71.46
	Dry Hole	9,932	57.12
Region 7	Oil	3,922	12.38
	Gas	5,953	24.36
	Dry Holes	4,614	10.46
Region 8	Oil	5,277	24.39
	Gas	5,428	23.23
	Dry Holes	4,472	14.58
Region 9	Oil	1,858	10.57
	Gas	2,464	13.42
	Dry Holes	1,701	6.63
Region 10	Oil	2,280	10.71
	Gas	3,928	13.57
	Dry Holes	3,651	12.11
Region 11	Oil	11,552	20.79
	Gas	-	-
	Dry Holes	10,927	25.84

(1) From 1972 Joint Association Survey

TABLE V-15

AVERAGE DRILLING COST FOR GAS WELLS

	AVERAGE DEPTH (Feet)	PRODUCERS ($/Foot) 1972 (1)	PRODUCERS ($/Foot) 1974 ADJ. (2)	DRY HOLES ($/Foot) 1972 (1)	DRY HOLES ($/Foot) 1974 ADJ. (2)
REGION 2	6,250	23.50	30.76	16.30	21.34
	8,750	25.00	32.73	19.90	26.05
REGION 2A	8,750	97.77	127.98	82.50	167.99
	11,250	107.00	140.06	96.00	125.66
	13,750	140.00	183.26	125.00	163.63
REGION 3	4,375	15.04	19.69	14.81	19.38
	6,250	18.74	24.53	17.01	24.88
	8,750	21.44	28.06	24.91	32.61
REGION 4	4,375	18.58	24.32	10.17	13.31
	6,250	18.33	23.99	7.87	10.30
REGION 5	6,250	31.08	40.68	24.21	31.69
	8,750	35.98	47.10	28.71	37.58
	11,250	44.18	57.83	33.81	44.26
	13,750	56.58	74.06	45.61	59.70
REGION 6	6,250	26.71	34.96	17.56	22.99
	8,750	31.11	40.72	21.46	28.09
	11,250	40.71	53.29	28.76	37.65
REGION 6A	11,250	69.46	90.92	57.53	75.31
	13,750	77.46	101.40	62.53	81.85

TABLE V-15 (cont'd.)

AVERAGE DRILLING COST FOR GAS WELLS (CONT'D.)

	AVERAGE DEPTH (Feet)	PRODUCERS ($/Foot) 1972 (1)	PRODUCERS ($/Foot) 1974 ADJ. (2)	DRY HOLES ($/Foot) 1972 (1)	DRY HOLES ($/Foot) 1974 ADJ. (2)
REGION 7	6,250	24.96	32.67	15.68	20.53
	8,750	29.76	38.96	18.18	23.80
	11,250	37.36	48.90	24.28	31.78
REGION 8, 9	1,875	17.72	23.20	11.73	15.35
	3,125	17.32	22.67	13.73	17.97
	4,375	21.12	27.65	16.93	22.16
REGION 10	3,125	13.97	18.29	12.15	15.90
	4,375	13.77	18.02	12.55	16.43
REGION 11	8,750	34.40	45.03	28.34	37.10
(Used 6)	11,250	32.70	42.80	24.34	31.86
REGION 11A	8,750	73.03	95.60	57.03	74.65
*(Used 6A)	11,250	69.46	90.92	57.53	75.31

(1) From 1972 JAS Survey

(2) 1974 Cost Adjusted from 1972 using cost escalation factor of 1.424

Although each individual factor represents an assumption, collectively these factors have a smaller impact on total expenditures than the drilling expenditures estimates made by the exploration and reserve development sub-models. The costs estimated include the following:

- Operating Expenses

  Geological and Geophysical
  Lease Rental
  Dry Holes
  Producing
  Overhead
  Ad Valorem & Production Taxes

- Depreciation

- Income Taxes

Annual Asset Accounting

Given the costs, the book accounting calculations are as follows:

- Beginning of Year Net Fixed Assets

  - Annual Additions

    Lease Acquisitions
    Successful Wells and Platforms
    Lease Equipment

  - Less Depreciation

- End of Year Net Fixed Assets

- Average Net Fixed Assets

The first item is industry's beginning-of-year investment in net fixed assets for the upstream functions. The initial investments are read in as data. Using the assumed drilling activity and the calculated oil production, the program determines all of the additions to the asset accounts. There are expenditures for lease acquisitions, successful wells and offshore platforms, and lease equipment (including all production facilities).

Depreciation, which includes all book write-offs, is calculated annually. The end-of-year net fixed assets are calculated next by adding the annual additions to the beginning-of-year net fixed assets and subtracting the depreciation. Industry's annual average investment in net fixed assets is retained by the program, and is the base for future discounted cash flow calculations.

The gas "price" and production program section estimates "minimum acceptable prices" for gas based on proved reserves and cash expenditures estimated by the previous sub-models. This is accomplished in three steps:

- A fifteen-year schedule of proved reserve additions (and the long-run price expectation necessary to provide a specified rate of return on cash flow) is estimated for each reserve added, based on a specified production profile, cash inflows and outflows over time and a specified reservoir life. The estimates employ a standard discounted cash flow technique. Separate schedules are produced for old and new reserves.

- Next, future production from each reserve addition is estimated. This production vintaging technique employs the same reservoir production profile used to estimate the required price.

- Finally, the results of the preceding two steps are combined to produce a schedule of quantities of gas produced in each of fifteen years over the range of required "price" computed initially.

Generally, these "price" and production calculations only manipulate estimates of reserve additions and cash expenditures made in the preceding parts of the model. Consequently, the results are subject to all of the uncertainties affecting the earlier estimates. In addition, however, several other factors affect the supply curve estimates, as follows:

- Discount rate (the initial estimates employ a fifteen percent rate).

- Decline rate (typically equal to the production/reserve ratio, or the fraction of the remaining reserves produced in each year).

- Project lives, or time to abandonment.

- All investment-type cash flows were assumed to occur in a single "year zero". In turn, peak production is assumed to occur in the first producing year. In mature provinces this has a minor effect. In virgin provinces, however, this probably understates price and overstates production in the early years of each reservoir.

1. Inputs to the Discounted Cash Flow, The results of the DCF calculations are sensitive to discount rate and project lives. The assumptions used in each area are shown below:

   - Discount rate: 10 percent for all regions, all years, and all recovery methods.
   - Project lives, for all regions and all years, were 30 years.

Make-up of DCF Calculations

Over the project life specified the DCF calculations uses the following logic:

(1) Year zero Cash flow = Cash Expenditures, Before Tax
- Expensed Items x (1 - tax rate)
- Items Eligible for Tax Credit x Tax Credit Rate

= Cash Flow, After Tax

(2) Annual Cash Flows

(2a) Cash Flow = Revenues, Net of Royalties and Production Taxes

- Cash Expenses

- Income Taxes

= Cash Flow, After Tax

(2b) Income Taxes = Net Revenues

- Cash Expenses

- Non-Cash Expenses

(calculation continued, next page)

Profit, Before Tax

x Tax Rate

= Income Taxes

2. Specific DCF Calculations

In practice, the model fixes the desired discount rate (presently 10 percent) and solves for the new gas price which provides sufficient revenues to yield this rate, given all of the other cash inflows and outflows.

(3) Present Value Equivalent:

	Year '0':	(1) x 1.0
+	Year 1:	(2) x single payment present value factor (year 1, 15%)
+	Year 2:	(2) x single payment present value (factor year 2, 15%)
+	etc	
+	etc	
+	Year 30:	(2) x single payment present value factor (year 3, 15%)

In operation, the model fixes the discount rate and solves for the oil price which makes the sum in (3) above, equal zero.

3. Make - up of Cash Flow Items:

(1) Year '0' Cash Flow

- o Cash Expenditures, Before Tax: Successful Wells + Dryholes + Lease Acquisitions + Environment and Safety + Geological, Geophysical + Lease Equipment + Lease Rentals + Overhead
- o Expensed Items: Dry Holes + (Successful Wells x .7) + Lease Rentals + Overhead
- o Items Eligible for Tax Credit: (Successful Wells x .3) + Environment and Safety + Lease Equipment

- Tax Rate: .50
- Tax Credit Rate: .07

(2) Annual Flows

- Revenues: Gross Revenues = Oil Produced x Price

    - Royalty = Gross Revenues x .129

    Net, Before Ad - Valorem

    (1 - Ad valorem rate)

    Net Revenue

  Identical calculations are performed for three coproducts of oil: associated dissolved gas, associated dissolved condensate and LPG. In each case, the price is an input variable and is constant for all years at t[illegible] following levels:

A-D Gas	:	$1.50 per Mcf
Condensate	:	$9.00 per barrel
LPG	:	$9.00 per barrel

- Cash Expenses: Producing Well Expense + Overhead + Environment and Safety Expense + Producing Geological, Geophysical Expense.

- Income Taxes: (Net Revenue - Cash Expenses - "effective" Depletion (@18 percent of Net Revenue)

    - Depreciation) x Tax Rate

Costing for Special Regions and Sources

In addition to the supply curves generated by the PIB-modified NPC program for lower-48 conventional production. production levels were generated manually by the Natural Gas Task Force Staff for the Alaskan Regions (Region 1-North and 1-South), including the Prudhoe Bay field, other private development, and Naval Petroleum Reserve No. 4; and for unconventional sources in the lower-48, including gas from stimulation of impermeable reservoirs and gas occluded in coal.

Projections of required investment, operating expenses, and appropriate state and federal taxes for Alaskan activity were projected in accordance with generally accepted industry practices, and similar projections for tight gas were prepared by the Natural Gas Task Force. After preparing a tabulation of production and all expenses and capital investments, a discounted cash flow analysis was performed using appropriate oil and gas prices according to the calculation procedure outlined in Table V-16. Future net income was discounted to present value using a discount rate of 15 percent per year. The discount rate was applied after payment of federal income taxes for all privately-owned production. In each case the oil or gas price was adjusted until the sum of the discounted net cash flow was approximately zero. This value is the minimum price for each case which will yield a 15 percent rate of return for that project.

TABLE V-16

DISCOUNTED CASH FLOW
CALCULATION PROCEDURE PERFORMED ON A YEARLY BASIS
FOR SPECIAL REGIONS/SOURCES

Gross Income = (1-Royalty Fraction) x [(Gross Oil Production x Oil Price) + (Gross Gas Sales x Gas Price)]

Operating Expense = Direct Operating Expense + (State Tax Fraction x Gross Income)

Net Operating Income = Gross Income - Operating Expense

Net Operating Income Less Capital = Net Operating Income - Capital Investment During Year

Discounted Net Operating Income Less Capital = Net Operating Income Less Capital x $(1/(1 + i)^{n-\frac{1}{2}})$

Where: i = Discount Rate, Fraction
n = Number of years

Tangible Investment - Capital Investment x Tangible Investment Fraction

NOTE: Tangible Investment is depreciated over life of project on a unit of production basis.

Intangible Investment - Capital Investment - Tangible Investment

Taxable Income = Net Operating Income - Intangible Investment - Depreciation on Tangible Investment

Federal Income Tax - Taxable Income x Tax Rate
Tax Rate Used - 48%

After Tax Net Income - Net Operating Income - Federal Income Tax

Net Cash Flow = After Tax Net Income - Capital Investment During Year

Discounted Net Cash Flow = Net Cash Flow x $(1-i)^{n-\frac{1}{2}})$

Where: i - Discount Rate, Fraction
n = Number of years

NOTE: This calculation procedure is performed for each year of the projection and then each category is summed. Discounting method represents present worth of future income for one payment received at the middle of each year.

Costs and necessary investments were estimated for Alaskan gas as follows:

Drilling Costs	$ 2.00	million per well
Gas Production Facility	0.95	per 6 wells
Pad and Site	1.30	
Compressor	1.00	
Flowlines	1.25	
Roads, culverts, docks, bridges, misc.	0.70	
Field Camp	0.20	
Fuel and Power Plant	0.60	
Operating Cost	$60,000.00	per well per year

Dry Hole Cost = 50% of Successful Well Cost

The projected production rates and numbers of wells necessary to reach those rates were used to calculate costs and requirements according to the above schedule for use in costing Alaskan gas. State taxes (severance and _ad valorem_) were set at 8%, Federal income tax at 48%, royalty rate at .167, tangible/intangible expense ratio at 1.0 with cost depletion used, and rate of return at 15%.

Costs and minimum acceptable price for gas from stimulation of impermeable reservoirs were estimated from data presented by the National Gas Technology Task Force for the Technical Advisory Committee of the National Gas Survey by the Federal Power Commission on April 1, 1973, particularly on page II-4 of their report. The cost escalation factors for inflation were removed, and the resulting values were extrapolated forward and backward to Project Independence target years, and adjusted to a 10% rate of return. Assumptions included an ad valorem tas rate of 5.5%, severance tax of 1%, Federal income tax of 48%, depletion allowance of 22%, royalty rate of 12.5%, and a rate of return of 10%. Investment per well was assumed to be 1 million dollars, and operating costs were assumed to be $2,000 dollars per well per year.

With respect to gas occluded in coal seams, it was found that the only feasible means of production merely required sinking of mineshafts two or three years earlier than normal in advance of mining, and that revenues from sale of recovered methane plus savings from simplification of mining operations due to degasification would on average offset the interest costs of early development. Thus, no costs or investments were estimated for gas from this source. In any event, the volumes of gas production involved are negligible, as mentioned elsewhere in this report.

Resource Requirements Assumptions and Procedures

For the lower-48 conventional sources the previously projected (NPC program, as updated) regional schedules of exploration and reserve development served as a basis for projecting resource requirements for each year's activity. For the special sources and regions the manually projected schedules were used. In either case, the procedure followed is described in detailed but simplified form in Table V-17 The "constants" required for all regions are given in Table V-18 All regions labelled as "A" regions are offshore.

In the case of gas from Alaska, it was assumed that all drilling rigs would have depth capacities of 1,500 feet or more. Since an insignificant amount of onshore drilling would be done south of the Brooks Range and offshore water depths are shallow (less than 100 fathoms) over large areas of the Gulf of Alaska and Cook Inlet, it was further assumed that all drilling in sub-region 1S would take place from fixed platforms. All drilling rigs used for development of "tight gas" in Colorado, Wyoming and Utah were assumed to have 10,000 to 11,500 foot depth capacity.

Table V-17

Methodology for Development of Materials and Labor Requirements

Estimates of materials and labor requirements for fabricated equipment, steel and labor required during the exploration, development and production phases of oil and gas supply operations up to the point of custody transfer were made using a linear algorithm keyed to drilling activity and production levels. The equational logic of the model for one region, one activity level, one scenario and one year (a simplified version) is outlined below. All cumulative calculations have been deleted for clarity, as have all scaling factors as the latter are dependent on input units.

Equation

(1) Exploration drilling footage = Total drilled footage X % exploration drilling

(2) Number of Dry Holes = $\dfrac{\text{(Exploration footage X \% dry) + (Development footage X \% dry)}}{\text{Average Hole Depth}}$

(3) Number of Successful Wells = $\dfrac{\text{(Exploration footage X (1-\% dry)) + (Development footage X (1-\% dry))}}{\text{Average Hole Depth}}$

(4) Total Holes = Dry holes + Successful wells

(5) G&G (Seismic) crew months = G&G (Seismic) crew months previous year X $\dfrac{\text{Total drilling footage}}{\text{Total drilling footage previous year}}$

(6) G&G (Seismic) crews = $\dfrac{\text{G\&G (Seismic) crew months}}{\text{12 X G\&G (Seismic) crew utilization factor}}$

(7) Tubular goods steel = (Number of dry holes X Tube steel/dry hole) + Number successful wells X Tube steel/successful wells

(8) Rig years = Total hole/holes per rig per year

(9) Steel, surface and sub surface equipment = Successful wells X S&SE steel/well

(10) Rig man years = $\dfrac{\text{Rig years X No. men per operating hour X 24 X 365}}{2080}$

(11) Rig men = Rig men years X manpower utilization factor

(12) Current number of rigs = Rig years X $\dfrac{\text{\% rigs by depth capacity}}{\text{rig utilization factor}}$

(13) Number of new rigs = current number of rigs - number of rigs previous year

(14) G&G equipment = No. G&G (Seismic) crews X G&G equipment factors/crew

(15) Rig steel (New Rigs) = Number of new rigs X steel per rig by depth capacity

(16) If offshore:
- (16A) Number of substructures by type = total rigs X % substructure by type
- (16B) Steel, substructures = Number of substructures by type X steel per substructure by type
- (16C) Steel, flowlines = Number of wells X flowline steel/well
- (16D) Service Vessels = No. rigs X 2 steel, service vessels = service vessels X 4000 t./vesse

(17) Total steel = Tubular steel + surface and subsurface equipment steel + new rig steel + new substructure steel + flowline steel

(18) Steel by process and metallurgy = Total steel X type % factors

(19) Cement = Total drilled footage X tons cement/ft. factor

(20) Pumps = No. new rigs X pumps/rig factor

(21) Valves = No. successful wells X valves/well factor

(22) Heavy steel structural shapes = No. new rigs X tonnage factor by depth the capacity

(23) Total labor = production X master labor factor

(24) Labor by skill = Total labor X % factors by skill

Table V-18

Resource Requirements "Constants", All Regions, All Sources

Casing and Tubing Tonnage Factor, Dry Holes

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
Tons/Hole	91	29	60	27	21	17	24	203	5	5	5	5	104	200

Casing and Tubing Tonnage Factor, Successful Wells

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
Tons/Hole	227	60	97	65	38	83	316	30	44	44	44	44	223	350

Surface and Subsurface Equipment Tonnage Factor, Successful Wells

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
Tons/Hole	8A	77	84	77	77	77	77	84	77	70	70	70	84	100

Service Vessels Per Offshore Rig = 2

Steel Tonnage Per Service Vessel = 4000 tons

Flowline Tonnage Factor

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
Tons/well	66	2	14	3	3	4	9	27	7	7	7	7	3	30

Rig Percentage by Depth Capacity by Region

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
0-5000'	0.0	74.9	0.0	45.0	48.0	56.1	34.7	0.0	70.1	85.5	85.5	85.5	1.0	0.0
5-10000'	0.0	27.2	0.0	48.8	42.3	38.5	40.1	0.0	24.2	14.4	14.4	14.4	4.0	0.0
10-15000'	0.0	3.2	0.0	5.0	9.4	3.3	20.9	0.0	4.5	0.1	0.1	0.1	20.2	0.0
15000' +	100.0	0.4	100.0	1.0	0.2	1.4	4.0	100.0	1.0	0.0	0.0	0.0	74.7	100.0

Utilization Factor, Rigs

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
% use	40	80	70	70	60	80	80	70	70	70	70	70	80	50

Average Holes per Rig per Year

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
	1.8	17.0	4.0	17.0	17.0	17.0	17.0	5.0	17.0	17.0	17.0	17.0	2.0	3.0

Steel Tonnage per Onshore Rig by Depth Capacity

0-5000'	200 tons
5-10000'	250
10-15000'	300
15000' +	375

Offshore Rig Substructures, Percent by Type

Fixed Platform	47
Barge	6
Jack-up	23
Semi-submersible	27

Utilization Factor, Offshore Substructures = 60%

Steel Tonnage Per Offshore Rig = 800 tons

Steel Tonnage Per Offshore Substructure, by Type

Fixed Platform	3000 tons
Barge	5000
Jack-up	5000
Semi-submersible	8000

Table V-18 (cont.)

Average Regional Hole Depth

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
Feet	8864	3400	3900	5414	5195	4723	5883	9821	4565	3099	3099	3099	10426	12000

Steel Percentage Factor by Type

Castings	3
Forgings	1
Plate Alloy	15
Carbon	59
Tube Alloy	5
Carbon	17

Average Number of Crewmen per Operating Rig

Onshore	7
Offshore	30

Ratio of Actual Hours per Man-Year to Standard Man Year of 2080 Hours

Onshore	1.05
Offshore	1.08

Initial Fraction of Total Seismic Crew Months by Region

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
Fraction	.0072	.0289	.0082	.0726	.0963	.0958	.3227	.0471	.1478	.1455	.1455	.1455	.0236	.0043

Initial Seismic Crew Months

Total	3374
Oil	2362
Gas	1012

Seismic Crew Utilization Percent

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
% use	60	80	50	80	80	80	80	60	80	80	80	80	80	60

Number of Equipment Items per Onshore Seismic Crew

Shot Hole Drills	2
Surface Energy Sources	2
Trucks	10
Instrument	1

Initial Onshore Rig Count by Depth Capacity, Gas (Allocated from National Totals)

Region	1	2	3	4	5	6	7	8	9	10	11
0-5000'	0	0.7	5.5	8.3	18.9	31.2	41.8	-	-	51.9	0
5-1000'	0	0.6	16.5	16.0	31.7	88.1	36.9	-	-	28.4	0
10-15000'	0	0.2	4.2	6.0	9.8	122.9	18.0	-	-	0	0
15000' +	0	0.2	5.4	0.3	9.8	97.4	18.0	-	-	0	0

Initial Offshore Rig Count by Depth Capacity, Gas (Allocated from National Totals)

Region	1	2A	6A	11A
0-5000'	0	0	13	0
0-10000'	0	0	16	0
15000' +	2	0	33	0

Initial Offshore Substructure Count by Type, Gas (Allocated from National Totals)

Region	1	2A	6A	11A
Fixed Platform	2	0	296	0
Barge	0	0	7	0
Jack-up	0	0	16	0
Semi-submersible	0	0	13	0

Man-years (2080 Hours) per Billion Cubic Feet per Year = 7.37

Cement, tons per 1000' drilled by Region

Region	1	2	2A	3	4	5	6	6A	7	8	9	10	11	11A
Tons	10	6	10	7	12	6	6	8	5	6	6	6	5	9

Table V-18 (cont.)

Pumps per Rig by Depth Capacity and Onshore/Offshore

0-5000'	1
5-10000'	1.5
10-15000'	2
15000' +	2
Offshore	4

Valves per Successful Well by Depth and Onshore/Offshore, tons/1000'

0-5000'	.05
5-10000'	.5
10-15000'	1.5
15000' +	2.0
Offshore	6.0

Heavy Structural Shapes per Rig by Depth Capacity, tons

0-5000'	75
5-10000'	135
10-15000'	165
15000' +	250
Fixed Platform	800

Man-hours by skill percentages

SKILL	INDUSTRY EMPLOYMENT (percent of total)
TOTAL ALL SKILLS	100.00
Professional, Technical, Kindred	18.55
Engineers, Chemical	.32
Engineers, Civil	.30
Engineers, Electrical	.27
Engineers, Industrial	.22
Engineers, Mechanical	.39
Engineers, Metallurgical	.02
Engineers, Mining	.18
Engineers, Petroleum	3.17
Engineers, Sales	.14
Engineers, Other	.16
Chemists	.41
Geologists	4.32
Marine Scientists	.01
Physicists	.04
Mathmatician	.03
Statistician	.04
Chemical Technician	.59
Draftsman	1.17
Electrical, Electronic Technician	.21
Surveyor	.33
Industrial Technician	.00
Architect	.00
Agricultural Scientist	.00
Biological Scientist	.00
Agricultural & Biological Technician	.01
Mathmatical Technician	.00
Mechanical Technician	.00
Engineering, Science Tech., n.e.c.	1.05
Medical Workers, exc. tech.	.01
Health Technicians	.00
Computer Programmers	.57
Computer Systems Analysts	.30
Other computer specialists	.04
Other professional, technical	4.25

Table V-18 (cont'd.)

SKILL	INDUSTRY EMPLOYMENT
Managers, Officials, Administrators	9.95
Sales Workers	.71
Clerical Workers	13.50
Construction Craftsmen	2.16
Carpenters	.18
Brickmasons, stonemasons	.01
Bulldozer operators	.27
Cement and Concrete finishers	.01
Electricians	.57
Excavating, grading machine operators	.41
Painters, construction, maintenance	.17
Plumbers and pipefitters	.48
Structural metal craftsmen	.03
All other construction craftsmen	.02
Foremen, n.e.c.	5.37
Other craftsmen	10.49
Boilermakers	.06
Machinists	.34
Millwrights	.02
Sheet metal workers, tinsmith	.02
Mechanic, repairmen, installers	3.33
Electric power linemen, cablemen	.06
Power station operators	.02
Craneman, derri men, hoistment	.50
Inspectors, other	.48
Stationary engineers	5.46
All other craftsmen, kindred	.20
Operatives	36.02
Wilders and flame cutters	1.2
Asbestos workers	.00
Drillers, earth	5.71
Mine operators, n.e.c.	24.41
Oilers, greasers, exc. auto	.36
Stationary firemen	.07
Blasters and powdermen	.25
Motormen; mine, factory, logging etc.	.29
All other operatives	3.73
Service and Protective Workers	1.28
Laborers	1.97

VI. SUMMARY OF RESULTS
AND
ANALYSIS OF PROJECTIONS

Introduction

As set forth in Section I of this report, the United States is faced with a grave and steadily worsening situation with respect to our domestic natural gas supply. In order to meet current needs we are drawing heavily upon our proved gas reserve inventory which has declined 25% since 1967. The current low rates of new additions to the reserve inventory are inadequate and have led to widespread curtailments of firm customers of interstate pipeline companies. The most palatable solution to the supply problem, barring substantial technological and social alterations in the production and consumption of gas, is the expansion of exploration efforts in both size and scope in the near future -- in the hope that significant new reservoirs and fields may be located and developed. A principal objective of the Project Independence Blueprint Natural Gas Task Force was to develop projections of what might (not what will) happen if such an effort were undertaken. Upon inspection it is debatable whether the absolute levels of projected costs and therefore the "minimum acceptable prices" of projected new reserve additions, as developed using the modified NPC program, are reasonable and accurate primarily due to price sensitivity to the multitude of necessary assumptions which affect each region somewhat differently. However, the relative cost/price relationships between regions, both within and across scenarios, are less sensitive to these assumptions. The bulk of this analysis is therefore devoted to a discussion of these relative relationships and their primary assumption sensitivities. Frequent reference should be made to Tables VI-1 through VI-8, which summarize the results of the modified NPC program and manual projections of new reserve additions and production for the Project Independence Blueprint cardinal years.

Conventional Source Additions, Lower 48 States, Non-Associated Gas

The Business As Usual scenario resulted in annual additions to reserves (see Table VI-1) which appear attainable in view of

Table VI-1

Summary of Non-Associated Reserve Addition Projections
and their "Minimum Acceptable Prices"
Lower 48 States 1/

NPC Region		1974 Reserve Additions	1974 "Price"	1977 Reserve Additions	1977 "Price"	1980 Reserve Additions	1980 "Price"	1985 Reserve Additions	1985 "Price"	1988 Reserve Additions	1988 "Price"
2	BAU 2/	0.100	$0.60	0.156	$0.65	0.213	$0.66	0.278	$0.69	0.283	$0.71
	ACC 3/	0.100	0.60	0.188	0.64	0.258	0.66	0.292	0.69	0.293	0.72
2A	BAU	0.0	--	0.105	0.69	0.129	0.71	0.277	0.80	0.288	0.86
	ACC	0.0	--	0.253	0.66	0.313	0.68	0.582	0.76	0.649	0.82
3	BAU	0.349	0.79	0.410	0.78	0.512	0.80	0.722	0.83	0.751	0.84
	ACC	0.349	0.79	0.494	0.78	0.611	0.80	0.728	0.83	0.780	0.84
4	BAU	0.407	0.35	0.530	0.48	0.621	0.51	0.840	0.58	0.802	0.62
	ACC	0.407	0.35	0.634	0.49	0.725	0.53	0.816	0.59	0.843	0.63
5	BAU	1.969	0.31	2.144	0.47	2.364	0.58	2.872	0.63	2.580	0.75
	ACC	1.969	0.31	2.534	0.48	2.772	0.60	2.742	0.67	2.614	0.77
6	BAU	3.992	0.43	4.245	0.54	4.412	0.61	4.428	0.86	3.455	1.20
	ACC	3.992	0.43	5.046	0.54	5.103	0.64	4.166	0.91	3.301	1.34
6A	BAU	3.753	0.29	5.938	0.35	7.195	0.44	6.774	0.71	5.445	0.96
	ACC	3.753	0.27	7.141	0.34	8.846	0.45	7.368	0.79	5.411	1.28
7	BAU	1.724	0.47	1.661	0.55	1.888	0.61	2.452	0.69	2.429	0.73
	ACC	1.724	0.47	1.978	0.56	2.206	0.62	2.424	0.70	2.559	0.74
8 & 9	BAU	0.049	0.77	0.037	1.04	0.034	1.23	0.036	1.81	0.030	2.42
	ACC	0.049	0.77	0.045	1.04	0.042	1.23	0.038	1.81	0.033	2.42
10	BAU	0.716	0.78	0.747	0.70	0.843	0.70	1.117	0.80	1.114	0.84
	ACC	0.716	0.78	0.901	0.70	0.976	0.73	1.101	0.81	1.158	0.85
11	BAU	0.0	--	0.003	5.78	0.007	5.80	0.010	5.79	0.010	5.79
	ACC	0.0	--	0.003	5.78	0.008	5.80	0.010	5.79	0.012	5.79
11A	BAU	0.0	--	0.0	--	0.064	0.89	1.847	0.92	1.922	0.95
	ACC	0.0	--	0.0	--	0.627	0.85	3.199	0.88	4.762	0.90
Sum of Additions:											
	BAU	13.059		15.976		18.282		21.653		19.109	
	ACC	13.059		19.217		22.487		23.466		22.415	

1/ Volumes in trillions of cubic feet, "prices" in cents per Mcf (constant 1973 dollars).
2/ Business as Usual Scenario.
3/ Accelerated Development Scenario.

both recent increased drilling for gas and the historical finding rates of the various regions. It should be noted, however, that if recent drilling increases prove to be of short term duration the additions projected will be overly optimistic.

Nationally, and in all regions except 2, 2A, 3 and 11A, BAU projected reserve additions peaked between 1980 and 1988 as a result of declining findings per foot drilled. The so-called "frontier" regions, 2A and 11A, contributed significant increments of new reserves after coming onstream in 1977 and 1980, respectively, reflecting their potential as possible supplements to presently active but declining source of domestic supply.

The "minimum acceptable prices" associated with the reserve additions are best interpreted as an estimate of the minimum economic cost of finding and producing these reserves, subject to the exclusion of lease bonuses and rentals and the inclusion of a 10% DCF rate of return. They bear no direct relation to marketed price. The cost of developing future increments of reserve additions will be generally higher than current costs, particularly in offshore areas, reflecting progressively lower findings per unit of investment. The magnitudes of projected "price" escalations over the period vary markedly from region to region, dependent primarily upon the individual effects of the regional finding rate curves. Those regions with the most constant finding rate in response to increasing cumulative drilled footage exhibited less escalation than those in which the finding rates were decreasing. Typically, "price" increased most dramatically in those well developed regions (5, 6 and 6A) from which most of our present production originates and in those regions which are currently least productive (8 and 9). An exception to the latter was region 11 which exhibited virtually no price increase but remained instead at a rather high price throughout the period because of very low reserve additions. The remaining moderately productive regions, including those which were still in an early stage of development (2A and 11A) exhibited correspondingly moderate "price" increases in the range of 6 to 77 percent over the projection period, in contrast to the 142 to 231 percent increases in the most, and least, productive regions.

Reserve additions in the Accelerated Development scenario differed from the Business As Usual additions primarily in offshore regions 2A and 11A, where activity is assumed to increase in response to increased producer incentives, including early opening of these areas to exploration. Regions 6 and 6A peaked sooner than in the Business As Usual scenario in response to moderate increases in drilling activity and as a result exhibited lower additions in 1988 -- due once again to the decrease in findings per foot drilled outrunning the increase in footage drilled. Only minor "price" increases occurred in the majority of regions in comparison with the Business As Usual "prices", the exceptions being those in which the productivity of capital decreased. Reductions in "price" on the order of 5% were experienced in "frontier" regions 2A and 11A as a result of more rapid development along an invariant finding curve.

It is clear that a dramatic reversal in the gas development trends of recent years will be required in order to approach the levels of potential production suggested by the two alternative scenarios. An examination of the production possibilities available from either scenario (Table VI-3) shows that the 1973 level of 16.5 trillion cubic feet of marketed non-associated gas production in the lower 48 states will not likely be reached again until about 1985 when production could possibly range between 17.4 and 19.1 trillion cubic feet. It must be remembered that the attainment of this level of production is predicated upon the evolution of the record high drilling programs inherent to both the BAU and ACC scenarios. These facts, coupled with the realization that our estimates of productivity are at best only educated guesses (especially in the "frontier" areas), serve to highlight the critical role which gas from supplemental sources will play in the Nation's ability to meet its needs for gas in the years immediately ahead.

<u>Sensitivity Analyses</u>

Ten program runs in addition to the basic Business As Usual and Accelerated Development runs were made, using the Business As Usual scenario as a base. In each run a single important input variable was altered by a fixed amount in order to determine the sensitivity of the results to input variations. Two of these alterations affected both the amount of reserves added and "price", and the remainder affected "price" alone, as shown in Table VI-2.

(a) Sensitivity to Finding Rate

The finding rate was varied by a factor of 20 percent about the base BAU level, resulting in a 20 percent increase and a 20 percent decrease in total findings in each year in each region and nationally. Increase of the finding rate by 20 percent resulted in "price" decreases on the order of 16 to 20 percent, and a decrease of the finding rate by 20 percent resulted in "price" increases of 24 to 28 percent.

(b) Sensitivity to Rate of Return

Alternate rates of return were set at two levels, specifically 15 percent and 7.5 percent, as opposed to the Business As Usual value of 10 percent. In the 15 percent case, "prices" were increased by 28 to 33 percent and in the 7.5 percent case they were reduced 13 to 18 percent.

(c) Sensitivity to Depletion Allowance

The depletion allowance, 22 percent in the Business As Usual scenario as currently mandated by statute, was varied by 3 percent about that value. Only minor effects were noted; both the 19 percent and 25 percent cases resulted in "price" departures of one to three cents about the Business As Usual level.

(d) Sensitivity to Royalty Levels

In the Business As Usual scenario onshore royalties were set at one-eighth and offshore royalties were set at one-sixth, in line with historic practice. However, the statutory minimum royalty offshore is one-eighth, so a run was made using this value both onshore and offshore. Onshore "price" did not change, of course; offshore "price" was reduced by 2 to 6 cents.

(e) Inclusion of Lease Bonus and Rental Costs

Lease bonus and rental costs as estimated by the Task Force were included in one run in order to determine their "price" effect.

Table VI-2

Sensitivity of Projections of Reserve Additions and Their Corresponding "Minimum Acceptable Prices" to Altered Finding Rates and Costs
Non-Associated Gas, Business As Usual Scenario, Lower 48 States 1/

	1974		1977		1980		1985		1988	
	Reserves Added	"Price"	Reserves Added	"Price"	Reserves Added	"Price"	Reserves Added	"Price"	Reserves Added	"Price"
Region 2 (Pacific Coast Except Alaska)										
BAU, Unmodified	0.100	60	0.156	65	0.213	66	0.278	69	0.283	71
Finding Rate -- 20% Increase	0.120	50	0.187	54	0.256	55	0.335	69	0.340	71
-- 20% Decrease	0.080	75	0.124	80	0.170	82	0.222	69	0.227	71
15% DCF Rate of Return	0.100	77	0.156	83	0.213	84	0.278	89	0.283	91
7.5% DCF Rate of Return	0.100	52	0.156	56	0.213	57	0.278	59	0.283	61
25.0% Depletion Allowance	0.100	58	0.156	63	0.213	64	0.278	67	0.283	69
19.0% Depletion Allowance	0.100	62	0.156	66	0.213	68	0.278	71	0.283	73
Royalties One-Eighth Offshore	0.100	60	0.156	65	0.213	66	0.278	69	0.283	71
Lease Bonus and Rental Costs Included	0.100	67	0.156	72	0.213	73	0.278	76	0.283	79
Alternate Drilling Cost Escalation Rate	0.100	63	0.156	68	0.213	69	0.278	71	0.283	73
Region 2A (Pacific Ocean Except Alaskan Waters)										
BAU, Unmodified	--	--	0.105	69	0.129	71	0.277	80	0.288	86
Finding Rate -- 20% Increase	--	--	0.126	58	0.154	60	0.333	67	0.346	72
-- 20% Decrease	--	--	0.084	86	0.103	89	0.222	99	0.231	107
15% DCF Rate of Return	--	--	0.105	87	0.129	91	0.277	103	0.288	111
7.5% DCF Rate of Return	--	--	0.105	61	0.129	63	0.277	69	0.288	74
25.0% Depletion Allowance	--	--	0.105	67	0.129	70	0.277	78	0.288	84
19.0% Depletion Allowance	--	--	0.105	71	0.129	73	0.277	80	0.288	88
Royalties One-Eighth Offshore	--	--	0.105	66	0.129	68	0.277	76	0.288	82
Lease Bonus and Rental Costs Included	--	--	0.105	94	0.129	94	0.277	94	0.288	94
Alternate Drilling Cost Escalation Rate	--	--	0.105	76	0.129	82	0.277	90	0.288	95
Region 3 (Western Rocky Mountains)										
BAU, Unmodified	0.349	79	0.410	78	0.512	80	0.722	83	0.751	84
Finding Rate -- 20% Increase	0.418	65	0.490	64	0.613	65	0.867	68	0.902	68
-- 20% Decrease	0.280	101	0.329	99	0.411	102	0.578	106	0.601	107
15% DCF Rate of Return	0.349	103	0.410	102	0.512	105	0.722	109	0.751	111
7.5% DCF Rate of Return	0.349	68	0.410	66	0.512	68	0.722	70	0.751	71
25.0% Depletion Allowance	0.349	77	0.410	76	0.512	78	0.722	80	0.751	81
19.0% Depletion Allowance	0.349	82	0.410	80	0.512	82	0.722	85	0.751	86
Royalties One-Eighth Offshore	0.349	79	0.410	78	0.512	80	0.722	83	0.751	84
Lease Bonus and Rental Costs Included	0.349	88	0.410	86	0.512	89	0.722	92	0.751	93
Alternate Drilling Cost Escalation Rate	0.349	55	0.410	64	0.512	65	0.722	67	0.751	67
Region 4 (Eastern Rocky Mountains)										
BAU, Unmodified	0.407	35	0.530	48	0.621	51	0.840	58	0.802	62
Finding Rate -- 20% Increase	0.488	28	0.636	40	0.744	43	1.008	48	0.961	52
-- 20% Decrease	0.315	47	0.424	61	0.499	65	0.672	73	0.643	78
15% DCF Rate of Return	0.407	46	0.530	62	0.621	66	0.840	74	0.802	80
7.5% DCF Rate of Return	0.407	30	0.530	42	0.621	44	0.840	50	0.802	54
25.0% Depletion Allowance	0.407	34	0.530	47	0.621	50	0.840	56	0.802	61
19.0% Depletion Allowance	0.407	36	0.530	50	0.621	53	0.840	60	0.802	64
Royalties One-Eighth Offshore	0.407	35	0.530	48	0.621	51	0.840	58	0.802	62
Lease Bonus and Rental Costs Included	0.407	39	0.530	53	0.621	57	0.840	64	0.802	69
Alternate Drilling Cost Escalation Rate	0.407	32	0.530	45	0.621	47	0.840	53	0.802	57
Region 5 (West Texas and Eastern New Mexico)										
BAU, Unmodified	1.969	31	2.144	47	2.364	58	2.872	63	2.580	75
Finding Rate -- 20% Increase	2.363	24	2.573	39	2.836	48	3.446	52	3.096	61
-- 20% Decrease	1.575	42	1.715	60	1.891	73	2.298	81	2.064	95
15% DCF Rate of Return	1.969	42	2.144	62	2.364	74	2.872	83	2.580	97
7.5% DCF Rate of Return	1.969	26	2.144	41	2.364	50	2.872	54	2.580	64
25.0% Depletion Allowance	1.969	30	2.144	46	2.364	56	2.872	62	2.580	72
19.0% Depletion Allowance	1.969	32	2.144	49	2.364	60	2.872	65	2.580	77
Royalties One-Eighth Offshore	1.969	31	2.144	47	2.364	58	2.872	63	2.580	75
Lease Bonus and Rental Costs Included	1.969	35	2.144	53	2.364	64	2.872	71	2.580	83
Alternate Drilling Cost Escalation Rate	1.969	24	2.144	39	2.364	48	2.872	52	2.580	61
Region 6 (Western Gulf Basin)										
BAU, Unmodified	3.992	43	4.246	54	4.412	61	4.428	86	3.455	120
Finding Rate -- 20% Increase	4.781	33	5.089	43	5.300	49	5.297	70	4.154	98
-- 20% Decrease	3.203	57	3.401	70	3.523	80	3.558	110	2.755	154
15% DCF Rate of Return	3.992	58	4.245	72	4.412	82	4.428	113	3.455	157
7.5% DCF Rate of Return	3.992	35	4.245	45	4.412	52	4.428	73	3.455	103
25.0% Depletion Allowance	3.992	41	4.245	52	4.412	60	4.428	83	3.455	117
19.0% Depletion Allowance	3.992	44	4.245	56	4.412	64	4.428	88	3.455	124
Royalties One-Eighth Offshore	3.992	43	4.245	54	4.412	61	4.428	86	3.455	120
Lease Bonus and Rental Costs Included	3.992	49	4.245	61	4.412	70	4.428	97	3.455	135
Alternate Drilling Cost Escalation Rate	3.992	38	4.245	48	4.412	56	4.428	78	3.455	109

1/ All reserves in Tcf; all "prices" in constant 1973 cents per Mcf.

Table VI-2 (Cont.)

Sensitivity of Projections of Reserve Additions and Their Corresponding "Minimum Acceptable Prices" to Altered Finding Rates and Cost
Non-Associated Gas, Business As Usual Scenario, Lower 48 States

	1974		1977		1980		1985		1988	
	Reserves Added	"Price"	Reserves Added	"Price"	Reserves Added	"Price"	Reserves Added	"Price"	Reserves Added	"Price"
Region 6A (Gulf of Mexico)										
BAU, Unmodified	3.753	29	5.938	35	7.195	44	6.774	71	5.445	96
Finding Rate -- 20% Increase	4.504	22	7.125	28	8.635	35	8.128	57	6.534	78
-- 20% Decrease	3.002	38	4.750	47	5.756	58	5.419	91	4.356	123
15% DCF Rate of Return	3.753	38	5.938	47	7.195	58	6.774	92	5.445	123
7.5% DCF Rate of Return	3.753	24	5.938	30	7.195	38	6.774	61	5.445	83
25.0% Depletion Allowance	3.753	28	5.938	34	7.195	43	6.774	69	5.445	94
19.0% Depletion Allowance	3.753	29	5.938	37	7.195	46	6.774	73	5.445	89
Royalties One-Eighth Offshore	3.753	27	5.938	33	7.195	42	6.774	67	5.445	91
Lease Bonus and Rental Costs Included	3.753	106	5.938	106	7.195	106	6.774	106	5.445	106
Alternate Drilling Cost Escalation Rate	3.753	24	5.938	30	7.195	38	6.774	61	5.445	82
Region 7 (Midcontinent)										
BAU, Unmodified	1.724	47	1.661	55	1.888	61	2.452	69	2.429	73
Finding Rate -- 20% Increase	2.069	38	1.994	45	2.330	48	2.938	57	2.915	60
-- 20% Decrease	1.379	61	1.329	70	1.513	78	1.965	88	1.943	94
15% DCF Rate of Return	1.724	63	1.661	73	1.888	80	2.452	91	2.429	96
7.5% DCF Rate of Return	1.724	40	1.661	47	1.888	52	2.452	59	2.429	63
25.0% Depletion Allowance	1.724	46	1.661	53	1.888	59	2.452	67	2.429	71
19.0% Depletion Allowance	1.724	49	1.661	57	1.888	63	2.452	71	2.429	76
Royalties One-Eighth Offshore	1.724	47	1.661	55	1.888	61	2.452	67	2.429	73
Lease Bonus and Rental Costs Included	1.724	53	1.661	61	1.888	68	2.452	77	2.429	82
Alternate Drilling Cost Escalation Rate	1.724	35	1.661	41	1.888	46	2.452	52	2.429	55
Region 8 and 9 (Michigan Basin and Eastern Interior)										
BAU, Unmodified	0.049	77	0.037	104	0.034	123	0.036	181	0.030	242
Finding Rate -- 20% Increase	0.059	63	0.044	87	0.041	102	0.043	151	0.036	199
-- 20% Decrease	0.039	98	0.030	130	0.028	153	0.034	195	0.023	309
15% DCF Rate of Return	0.049	101	0.037	136	0.034	160	0.036	235	0.030	314
7.5% DCF Rate of Return	0.049	65	0.037	89	0.034	105	0.036	154	0.030	207
25.0% Depletion Allowance	0.049	75	0.037	102	0.034	120	0.036	176	0.030	236
19.0% Depletion Allowance	0.049	79	0.037	107	0.034	126	0.036	186	0.030	249
Royalties One-Eighth Offshore	0.049	77	0.037	104	0.034	123	0.036	181	0.030	242
Lease Bonus and Rental Costs Included	0.049	88	0.037	118	0.034	139	0.036	204	0.030	274
Alternate Drilling Cost Escalation Rate	0.049	52	0.037	75	0.034	90	0.036	138	0.030	175
Region 10 (Appalachians)										
BAU, Unmodified	0.716	78	0.747	70	0.843	70	1.117	80	1.114	84
Finding Rate -- 20% Increase	0.859	64	0.899	57	1.016	57	1.335	65	1.340	68
-- 20% Decrease	0.573	99	0.596	90	0.670	91	0.900	101	0.888	107
15% DCF Rate of Return	0.716	102	0.747	94	0.843	94	1.117	106	1.114	111
7.5% DCF Rate of Return	0.716	66	0.747	59	0.843	59	1.117	67	1.114	70
25.0% Depletion Allowance	0.716	76	0.747	68	0.843	68	1.117	78	1.114	81
19.0% Depletion Allowance	0.716	80	0.747	72	0.843	72	1.117	82	1.114	86
Royalties One-Eighth Offshore	0.716	78	0.747	70	0.843	70	1.117	80	1.114	84
Lease Bonus and Rental Costs Included	0.716	86	0.747	78	0.843	79	1.117	89	1.114	93
Alternate Drilling Cost Escalation Rate	0.716	70	0.747	63	0.843	63	1.117	72	1.114	75
Region 11 (Atlantic Coast)										
BAU, Unmodified	--	--	0.003	578	0.007	580	0.010	579	0.010	579
Finding Rate -- 20% Increase	--	--	0.003	481	0.008	482	0.012	482	0.012	482
-- 20% Decrease	--	--	0.002	724	0.005	725	0.008	725	0.008	725
15% DCF Rate of Return	--	--	0.003	754	0.007	755	0.010	755	0.010	755
7.5% DCF Rate of Return	--	--	0.003	495	0.007	496	0.010	495	0.010	495
25.0% Depletion Allowance	--	--	0.003	564	0.007	565	0.010	565	0.010	565
19.0% Depletion Allowance	--	--	0.003	593	0.007	595	0.010	594	0.010	594
Royalties One-Eighth Offshore	--	--	0.003	578	0.007	580	0.010	579	0.010	579
Lease Bonus and Rental Costs Included	--	--	0.003	644	0.007	645	0.010	645	0.010	645
Alternate Drilling Cost Escalation Rate	--	--	0.003	402	0.007	403	0.010	403	0.010	403
Region 11A (Atlantic Ocean)										
BAU, Unmodified	--	--	--	--	0.064	89	1.847	92	1.922	95
Finding Rate -- 20% Increase	--	--	--	--	0.077	74	2.217	76	2.306	79
-- 20% Decrease	--	--	--	--	0.051	113	1.478	116	1.537	119
15% DCF Rate of Return	--	--	--	--	0.064	126	1.847	130	1.922	134
7.5% DCF Rate of Return	--	--	--	--	0.064	73	1.847	75	1.922	78
25.0% Depletion Allowance	--	--	--	--	0.064	87	1.847	90	1.922	93
19.0% Depletion Allowance	--	--	--	--	0.064	92	1.847	94	1.922	97
Royalties One-Eight Offshore	--	--	--	--	0.064	85	1.847	88	1.922	90
Lease Bonus and Rental Costs Included	--	--	--	--	0.064	271	1.847	271	1.922	271
Alternate Drilling Cost Escalation Rate	--	--	--	--	0.064	81	1.847	83	1.922	86
Summed Reserve Additions										
BAU, Unmodified	13.059		15.976		18.282		21.653		22.109	
Finding Rate -- 20% Increase	15.661		19.166		22.010		25.959		22.942	
-- 20% Decrease	10.131		12.784		14.620		17.354		15.276	

1/ All reserves in Tcf; all "prices" in constant 1973 cents per Mcf.

Onshore "prices" were raised 9 to 14 percent, but offshore "prices" increased between 36 and 265 percent depending on the region and year (after the first year, bonuses were reduced as necessary from the maximum $2500 per acre level in order to keep "price" constant, but in no case to an amount less than $500 per acre).

(f) Alternate Drilling Cost Escalation Rate

The 1972-1974 drilling cost escalation factor of 30.9 percent used in the Business As Usual scenario reflects recent dramatic increases in the cost of contract drilling, which has gone up substantially in the past year. A projection based on 1972 and 1973 drilling cost statistics as published by the IPAA, and ignoring these recent developments, results in a lower cost escalation rate of 19.5 percent. If recent increases are primarily attributable to a temporary shortage of rigs, then the lower escalation rate might be more nearly correct over the projection period. While the Task Force cannot conclude that the rig shortage will be relieved in the near future, it did make a run to determine the possible "price" effect of the lower escalation factor. Its use resulted in a reduction of "price" by 10 to 30 percent depending on the year and region.

(g) Zero Federal Income Tax Rate

The Federal Power Commission has held that gas producers, in aggregate, pay no Federal income taxes, i.e., the tax credits generated by their investments exactly offset tax liabilities arising from subsequent production. This assumption was tested by setting the Federal income tax rate of the program to zero. The "price" results for equivalent production levels were within computational round-off error of each other for the "with" and "without" cases, with the notable exception of regions 2A, 6A and 11A (the offshore regions) where "price" was reduced 10 to 20 percent by removal of the tax.

<u>Conventional Source Production, Lower 48 States, Non-Associated Gas</u>

Table VI-3 is a schedule of the cumulative amounts of non-associated gas which would be produced from existing reserves plus the projected reserve additions previously discussed. In

Table VI-3

Total Non-Associated Gas Production Possibilities
Lower 48 States 1/

1974		1977		1980		1985		1988		"Minimum Acceptable Price"
BAU 2/	ACC 3/	BAU	ACC	BAU	ACC	BAU	ACC	BAU	ACC	of Last Mcf
16.522	16.522	13.132	13.133	9.683	9.683	5.509	5.509	3.812	3.812	$0.20
16.522	16.522	14.215	14.250	11.793	12.109	6.993	7.219	4.830	4.986	0.30
16.522	16.552	15.222	15.284	13.187	13.652	9.163	9.100	6.630	6.529	0.40
16.550	16.550	15.667	15.767	15.470	16.013	13.388	12.867	9.867	9.465	0.50
16.550	16.550	15.697	15.804	15.653	16.711	15.865	17.030	13.139	13.781	0.60
16.550	16.550	15.919	16.035	16.011	17.023	17.193	18.548	16.099	16.475	0.70
16.550	16.550	15.923	16.040	16.014	17.026	17.349	19.114	17.227	17.866	0.80
16.550	16.550	15.925	16.042	16.012	17.030	17.361	19.116	17.829	18.858	0.90
16.550	16.550	15.925	16.042	16.019	17.033	17.362	19.118	18.011	19.513	1.00
16.550	16.550	15.925	16.042	16.024	17.039	17.366	19.122	18.014	19.683	1.10
16.550	16.550	15.925	16.042	16.025	17.040	17.382	19.141	18.037	19.709	2.00 or more

1/ Volumes in trillions of cubic feet, "prices" in cents per Mcf (constant 1973 dollars).
2/ Business as Usual Scenario.
3/ Accelerated Development Scenario.

the schedule all old gas -- gas discovered prior to 1974 -- is included in the 20 cent line and all gas "priced" higher than $1.90 is included in the $2.00 or more line. These additional volumes are small. The remainder of the schedule consists of scheduled production from the reserve additions reported in Table VI-1 aggregated across regions and entered on the appropriate "price" line. A better picture of the incremental "minimum acceptable price" structure is given in Table VI-4 which was derived directly from Table VI-3. Here it is clear that as time progresses the newly found gas becomes available at required "prices" higher than those applicable to old gas. It is also clear that substantial amounts of the new reserves have "minimum acceptable prices" in the 100 cents or less per Mcf range. The weighted average "price" of all gas, and of all projected additions to reserves, as produced, are given at the bottom of the table. The "required average national price" is increased 150 percent over the 15 year projection period, from 20 cents to 50 cents per Mcf.

As discussed in detail elsewhere in the report, these schedules are not supply curves in an economic sense, as they were not derived in a manner consistent with the economic definition of a supply curve. They are merely the aggregated results of projections made without reference to market prices. Therefore, the schedules should not be read "Given a 'price' X, we project production Y", but rather, "Given a projected production level Y, we must have 'price' X to break even given our required rate of return and assumed findings per foot of hole drilled". This is a major distinction.

<u>Conventional Source Production, Lower 48 States, Associated-Dissolved Gas</u>

Table VI-5 contains the production figures for associated-dissolved gas, which is a co-product of the oil production projections made by the Oil Task Force. Note that this schedule shows production arising from their model assumption versus the required oil prices -- not gas price. Unfortunately, there is no method of stating these prices on a comparable basis which will withstand the test of reality. Little comment can be made about this source, since the gas is unavoidably produced with the oil and, unless re-injected to maintain reservoir pressure, must be sold at whatever current gas price level prevails, *i.e.*,

Table VI-4

Increments of Non-Associated Gas Production for Selected "Minimum Acceptable Price" Intervals 1/
Lower 48 States
(Derived from Exhibit 8)

"Price" Interval	1974 BAU 2/	1974 ACC 3/	1977 BAU	1977 ACC	1980 BAU	1980 ACC	1985 BAU	1985 ACC	1988 BAU	1988 ACC
0-20¢	16.552	16.552	13.132	13.132	9.683	9.683	5.509	5.509	3.812	3.812
20-30	0.0	0.0	1.083	1.117	2.110	2.426	1.484	1.710	1.018	1.174
30-40	0.0	0.0	1.007	1.034	1.394	1.543	2.170	1.881	1.800	1.543
40-50	0.028	0.028	0.445	0.483	2.283	2.361	4.225	3.767	3.237	2.936
50-60	0.0	0.0	0.030	0.037	0.183	0.698	2.477	4.163	3.272	4.316
60-70	0.0	0.0	0.222	0.231	0.358	0.312	1.328	1.518	2.960	2.694
70-80	0.0	0.0	0.004	0.005	0.003	0.003	0.156	0.566	1.128	1.391
80-90	0.0	0.0	0.002	0.002	0.003	0.004	0.012	0.002	0.602	0.992
90-100	0.0	0.0	0.0	0.0	0.002	0.003	0.001	0.002	0.182	0.655
100-110	0.0	0.0	0.0	0.0	0.005	0.006	0.004	0.004	0.003	0.170
110-120	0.0	0.0	0.0	0.0	0.0	0.0	0.002	0.003	0.001	0.002
120-130	0.0	0.0	0.0	0.0	0.0	0.0	0.003	0.003	0.002	0.002
130-140	0.0	0.0	0.0	0.0	0.0	0.0	0.002	0.003	0.002	0.003
140-150	0.0	0.0	0.0	0.0	0.0	0.0	0.004	0.003	0.003	0.002
150-160	0.0	0.0	0.0	0.0	0.0	0.0	0.003	0.002	0.002	0.003
160-170	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
170-180	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.003	0.003
180-190	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.003	0.003
190 or higher	0.0	0.0	0.0	0.0	0.001	0.001	0.004	0.005	0.007	0.008
Sum of Increments:	16.55	16.55	15.925	16.042	16.025	17.040	17.382	19.141	18.037	19.709
Weighted Average Prices 4/										
For All Gas	20.08	20.08	22.70	22.82	27.00	27.87	37.50	39.81	46.57	49.58
For Production From Projected Discoveries	Nil Production	Nil Production	35.47	35.56	37.68	44.24	45.62	47.82	53.69	56.68

1/ "Prices" in cents per Mcf, volumes in Tcf.
2/ Business As Usual Scenario.
3/ Accelerated Development Scenario.
4/ Volumes weighted by mid-point "prices" of the intervals.

Table VI-5

Associated-Dissolved Natural Gas Production Production Projections
Lower 48 States and Alaskan Region 1S

Scenario	YEAR 1974	1977	1980	1985	1988	Minimum Acceptable Oil "Price"
Business As Usual	3.665	3.167	2.871	2.649	2.484	$ 4.00
	3.665	3.365	3.159	3.018	2.941	7.00
	3.665	3.079	3.084	3.827	3.994	11.00
Accelerated Development	3.665	3.327	3.128	3.083	3.000	4.00
	3.665	3.533	3.580	3.679	3.685	7.00
	3.665	3.539	3.709	4.415	4.761	11.00

Note: Production given in Tcf; Minimum Acceptable Price given in constant 1973 dollars per barrel.

this source is not sensitive to gas price (or gas demand) but to oil price (and oil demand).

Alaskan Production

Alaskan production projections were broken into two geographic zones, Alaska north of the Brooks Range (Region 1N) and south of the range (Region 1S), primarily because 1N production is onshore and 1S production is offshore. Further, the special regions/sources, of which the Alaskan regions are a part, were projected manually for both scenarios at three specific activity levels. The results are not as amenable to treatment as continuous supply possibility schedules as were the production and price projections for the lower 48 states. Note that within activity levels, "price" is constant while production changes, a result of the estimating methodology employed wherein finding rates were assumed constant. Significant amounts of gas are projected to be produced in each Alaskan region from both types of sources at a "price" which itself appears to be generally in line with those calculated for Lower 48 conventional production. Alaskan production projections are detailed in Table VI-6.

Production of Gas from Stimulation of Tight Formations and of Gas Occluded in Coal Seams

Of these two special sources, only gas from tight formations is producible in significant quantities, conditional upon commercially successful, full scale field testing of massive hydraulic fracturing in the highly impermeable sandstone reservoir rocks containing the gas. Assuming such a result, the projected production and "prices" are given in Table VI-7. Note that production from coal seams is "price-less" since the operation has been determined to be "costless" and the gas will be sold at whatever the prevailing market price might be.

Capital, Materials and Labor Requirements

Based upon its projections of industry activity and production, the Task Force estimated the amounts of capital, materials and labor required. The most accurate of these derived values was for capital, and the least accurate was for labor. Projections were made in each region for each year of the requirements for 21 possibly critical raw, semi-finished or fabricated material

Table VI-6

Alaskan Production Projections

Type of Gas/ Region/Scenario/ Activity Level	1974		1977		1980		1985		1988	
	Production	Price *	Production	Price	Production	Price	Production	Price	Production	Price
Non-Associated										
Region 1N										
BAU/Low	0.0	--	0.0	--	0.094	0.42	0.160	0.42	0.184	0.42
BAU/Medium	0.0	--	0.0	--	0.150	0.40	0.320	0.40	0.410	0.40
BAU/High	0.0	--	0.0	--	0.180	0.43	0.415	0.43	0.540	0.43
ACC/Low	0.0	--	0.0	--	0.225	0.81	0.485	0.81	0.615	0.81
ACC/Medium	0.0	--	0.0	--	0.270	0.53	0.630	0.53	0.814	0.53
ACC/High	0.0	--	0.0	--	0.295	0.53	0.690	0.53	0.895	0.53
Region 1S										
BAU/Low	0.120	0.30	0.135	0.30	0.155	0.30	0.310	0.30	0.352	0.30
BAU/Medium	0.120	0.47	0.150	0.47	0.225	0.47	0.470	0.47	0.630	0.47
BAU/High	0.120	0.56	0.150	0.56	0.225	0.56	0.560	0.56	0.792	0.56
ACC/Low	0.120	0.47	0.200	0.47	0.430	0.47	0.800	0.47	1.050	0.47
ACC/Medium	0.120	0.49	0.225	0.49	0.500	0.49	1.000	0.49	1.360	0.49
ACC/High	0.120	0.51	0.275	0.51	0.515	0.51	1.125	0.51	1.530	0.51
Associated-Dissolved										
Region 1N										
Prudhoe Bay, BAU, All Cases	0.0	--	0.0	--	0.675	2.24	1.350	2.24	1.350	2.24
Prudhoe Bay, ACC, Low	0.0	--	0.0	--	0.675	2.24	1.350	2.24	1.350	2.24
Prudhoe Bay, ACC, Medium and High	0.0	--	0.0	--	0.675	2.03	2.107	2.03	2.350	2.03
NPR 4/Low	0.0	--	0.0	--	0.0	6.02	0.885	6.02	1.270	6.02
NPR 4/High	0.0	--	0.0	--	0.0	9.03	0.885	9.03	2.381	9.03
Other Areas	0.0	--	0.0	--	0.169	5.89	0.571	5.89	0.548	5.89

Region 1S - Included in Exhibit 10.

* Price given is gas price for non-associated production and oil price for associated-dissolved production.

Note: Production given in Tcf, "Minimum Acceptable Price" given in constant 1973 dollars per Mcf or per barrel; BAU = Business As Usual. ACC = Accelerated Devlopment. AD price projections for Region 1N are not yet updated, and will be included in the final report.

Table VI-7

Projected Production of Gas from Special Sources

Source/Region/Scenario/ Activity Level		1974		1977		1980		1985		1990	
		Production	Price	Production	Price	Production	Price	Production	Price	Production	Price
Tight Reservoirs/											
Region 3/	BAU/Low	0.0	--	0.0	--	0.0	--	0.0	--	0.0	--
	BAU/Medium	0.0	--	0.0	--	0.0	--	0.0	--	0.0	--
	BAU/High	0.0	--	0.0	--	0.1	0.34	0.2	0.40	0.3	0.46
	ACC/Low	0.0	--	0.0	--	0.1	0.46	0.3	0.54	0.5	0.58
	ACC/Medium	0.0	--	0.0	--	0.2	0.43	0.3	0.56	0.5	0.61
	ACC/High	0.0	--	0.0	0.29	0.8	0.32	1.5	0.38	1.7	0.42
Region 4/	BAU/All Levels	0.0	--	0.0	--	0.0	--	0.0	--	0.0	--
	ACC/Low	0.0	--	0.0	--	0.0	--	0.0	--	0.0	--
	ACC/Medium	0.0	--	0.0	--	0.1	0.48	0.3	0.56	0.3	0.61
	ACC/High	0.0	--	0.0	--	0.3	0.32	0.5	0.38	0.6	0.42
Occluded in Coal * /											
Region 6/	BAU	0.0	--	0.0003	--	0.0004	--	0.0006	--	0.0005	--
	ACC	0.0	--	0.0009	--	0.001	--	0.002	--	0.003	--
Region 9/	BAU	0.0	--	0.003	--	0.005	--	0.007	--	0.007	--
	ACC	0.0	--	0.010	--	0.016	--	0.025	--	0.036	--
Region 10/	BAU	0.0	--	0.003	--	0.005	--	0.006	--	0.006	--
	ACC	0.0	--	0.010	--	0.015	--	0.024	--	0.034	--

Note: Production given in Tcf, "Minimum Acceptable Price" given in constant 1973 dollars per Mcf; BAU = Business As Usual, ACC = Accelerated Development

* No activity levels, as this source is controlled by mining activity.

goods, the number of exploratory crew-months and the number of drilling rig personnel man-years, and for labor requirements in total and broken out by 74 occupational skill categories. The materials and labor data, too voluminous to summarize here in a meaningful way, will be considered by the integrating effort to determine possible constraints on production.

The capital required to support the projected activity is large. Table VI-8 indicates the possible capital requirements arising from the exploration for, and production of non-associated gas in the lower 48 states outlined in Table VI-3. These capital requirement projections will be analyzed intensively in the integrating effort in view of possible financing constraints.

Analytical Conclusions

Setting aside the question of the absolute accuracy of the calculated "minimum acceptable prices" the Natural Gas Task Force concludes that the production possibilities estimated herein are representative of the upper limits of production attainable in the context of the relevant scenarios. The majority of future domestic gas supply will clearly come from non-associated gas reservoirs, and even with the welcome incremental additions of gas from the other sources it is obvious that gas exploration efforts will have to be greatly expanded starting immediately and continuing, even increasing in intensity, throughout the projection period to remain at the level of satisfaction of demand which we are currently experiencing.

A further conclusion inescapable on the basis of these results is that in order to finance this exploration effort and to justify the investment risks associated with it, gas prices will have to be substantially increased in the future. The magnitude of necessary increases is, as demonstrated by the various sensitivity analyses summarized previously, controllable to some extent by alteration of various government policies including regulatory policy, tax policy, and offshore leasing policy, as well as more indirect policies generally affecting the national economy which ultimately are reflected in the direct costs of exploration for and production of domestic natural gas resources.

Table VI-8

Non-Associated Gas Investment Requirements, Lower 48 States 1/
Business as Usual 2/

1974	1977	1980	1985	1988	"Minimum Acceptable Price" of Last Mcf
1288	314	0	0	0	20 or less
1647	446	445	0	0	30
1647	883	793	0	0	40
1652	883	1120	506	286	50
1688	1023	1284	1187	595	60
1769	1037	1284	1788	766	70
1769	1037	1303	1937	1529	80
1769	1037	1306	1937	1569	90
1769	1037	1306	1937	2024	100
1769	1037	1306	1937	2024	110
1769	1037	1306	1937	2024	120
1769	1037	1306	1942	2024	130
1769	1037	1306	1942	2024	140
1769	1037	1306	1942	2024	150
1769	1037	1306	1942	2024	160
1769	1037	1306	1942	2024	170
1769	1037	1306	1942	2029	180
1769	1037	1306	1942	2029	190
1769	1038	1309	1946	2034	200 or more

1/ Capital requirements in millions of constant 1973 dollars, "price" in cents per Mcf.
2/ Corresponds to volumes in Exhibits 8 and 9.

VII ENVIRONMENTAL CONSIDERATIONS AND IMPACTS

General Impacts

In general, the development of conventional natural gas resources does not have significant long-term environmental consequences, particularly in relation to other fossil fuel resources. However, there are controllable environmental impacts associated with the construction, operation, maintenance and abandonment of the facilities needed to locate and produce natural gas. Since oil and natural gas are often found together, many of the environmental impacts for one apply as well to the other. The major difference in environmental impacts is the greater potential damage from an oil spill, although in gas operations there are usually smaller quantities of liquid hydrocarbons produced which, if spilled, are potentially damaging.

Air, water, and land quality may all be affected in the search for and production of natural gas. The impact on air quality stems principally from the emission of particulates into the atmosphere during gas production operations. Vapor vented from storage tanks and burning of waste products containing sulphur compounds are the major problems. A principal enviornmental risk of gas production is spillage of harmful materials such as salt water or chemicals into the local water supply. Also, the disposal of solid wastes such as drilling mud must be controlled. These considerations are magnified in offshore operations. Land quality is impacted in two ways: (1) land pollution from spillage of harmful substances, and (2) the impact of oil and gas operations on alternative uses of the land.

Onshore

Onshore geophysical surveys include the use of explosives and cutting of trails. While this is an ecologically temporary disturbance, water wells and irrigation facilities are sometimes damaged by the explosions. Oil and gas drilling operations require construction of temporary roads and well sites, and require water. Disposal of drilling mud, chemicals, and salt water is necessary. Air quality degradation stems principally from the emission of particulates such as dust from vehicle traffic, sulfur compounds from burning waste material, and occasional well blowout emissions.

Noise and vibrations occur in drilling with a resulting potential temporary impact on wildlife, wilderness qualities, and hunting. Land area required per well varies greatly depending on the geographical location. A deep wildcat drilling location, including rig and drilling mud pits could require about 3 acres, excluding access for roads or utilities. Road right-of-way is generally about 3.6 acres per mile.

The wilderness environment of Alaska greatly increases the potential for damage from all sources associated with conventional onshore operations: oil spills; discharges of brines, chemicals, and other toxic materials; and disturbance of biota by construction. Maintenance of the permafrost is very important, as freezing and thawing have an adverse impact on the structure and stability of the soil. This is not much of a problem in northern Alaska, but areas of discontinuous permafrost found in Central Alaska present major problems. Effects of earthquake activity must be considered, although, relative to southern Alaska, the North Slope is an area of moderate structural complexity and earthquake activity. The rich, unique vegetation and animal life of Alaska are particularly susceptible to impact from industrial activity and must be considered accordingly. As the largest remaining wilderness area in the U.S., Alaska's value as a wilderness resource is immeasurable. Development of natural gas will alter some of this wilderness. About 7,000 acres of land will be required to fully develop the Prudhoe Bay oil and gas field alone.

Offshore

Geophysical exploration poses virtually no environmental risk to offshore areas but exploratory drilling is one of the most hazardous offshore operations where the greatest danger is from accidental fires or blowouts. Because of the possibility of storm and earthquake damage and fire, automated safety devices are installed on the platform to stop or control the flow of gas. Wells also must be equipped with a subsurface safety valve which will shut down the well in case of surface equipment failure.

As with onshore operations, the disposal of drilling effluents such as chemicals, brine, and drilling mud must be controlled, but in offshore operations, the opportunity exists through water movement for a more widespread though perhaps less severely affected impact area.

Another unique aspect of offshore operations is its onshore environmental impact in the form of land development, construction disruptions, and air, water, and noise pollution traceable to the support and terminal facilities needed to serve the offshore activity. The availability of land for these onshore facilities varies from one offshore region to another. Also, while the above mentioned environmental hazards can occur at any offshore location, the possibility of occurrence and the extent of potential environmental damage differ among offshore areas because of diverse ecological and weather conditions.

Most hurricanes and tropical cyclones influencing the Gulf of Mexico form in the Eastern Caribbean or the Central Atlantic and there is advance warning, sometimes several days. When the Weather Bureau advises that a hurricane is imminent, all oil and gas facilities in, or adjacent to, the path of the storm are evacuated and all surface and wellhead controls are shut-in. Both storm-induced wind waves and swells are significantly lower in the Gulf of Mexico than along the Pacific and Atlantic Coasts. Seismic activity is low and infrequent in this area. The coastal areas of the five states bordering the Gulf of Mexico are richly endowed with about two-thirds of the total coastal marshes and one-third of the estuarine water area in the U.S. These waters are very productive of both sport and commercial fish and wildlife resources. In addition, the marshlands, beaches, freshwater, and saltwater areas of the Gulf are important recreation areas.

The Atlantic Coast is characterized by major low-pressure storm systems moving through the region in a north to east-northeast direction accompanied by strong, gusty winds and heavy seas. The Middle and South Atlantic offshore areas are subjected to more severe conditions due to hurricanes than either the Gulf of Alaska or the North Sea. The Atlantic offshore area is subject to moderate seismic activity.

The areas for potential exploratory activity in the Atlantic offshore area range from Maine to Florida and include much prime fishing and recreational areas. Although massive oil spills caused by blowouts, fires, and tanker collisions receive the most publicity, it is the routine production of oil and gas that presents considerable environmental risk. Daily operational discharges of oil, drilling muds, cuttings and other material may result in sublethal or long-term ecological damage to the area if allowed.

While the weather influencing the Santa Barbara Channel of the Pacific offshore area is generally more moderate than in the other offshore areas, the seismic activity is higher. Not only is there danger of well damage from an earthquake itself, but from possible secondary damage due to Tsunami waves generated either locally or distantly. Automatic chokes and cutoff valves should prevent major spillage impacts from well or pipeline ruptures. In addition to impacts similar to the offshore regions already discussed, land supply for onshore operations may be a problem on the Pacific Coast. It may be extremely difficult, for example, to find enough land in the San Francisco Bay area where environmental and locational constraints remove about 90 percent of the undeveloped land from availability.

The most unique aspect of Alaska offshore operations is the icing problem. In addition, severe weather and high seismic activity are encountered. Otherwise, environmental impacts will be similar to the other offshore areas, with the exception that Alaska is a wilderness area. (See discussion on Alaska onshore operations).

Special Sources

Two special sources of natural gas production were considered by the Natural Gas Task Force, massive hydraulic fracturing of low-permeability natural gas reservoirs and methane occluded in coal. Neither of these sources pose significantly different environmental impacts than have been previously discussed for conventional onshore gas operations.

VIII PRODUCTION CONSTRAINTS

Present Constraints

A variety of factors may currently be exerting a constraining effect on the development and production of non-associated natural gas. Some of these factors are related to the fact that the natural gas industry is the most heavily regulated of the energy industries. As a result of Federal and State legislation the production, transportation and sale of the major portion of our natural gas production is regulated from wellhead to burner tip to ensure observance of the principles of conservation and to protect consumers from possible monopolistic or oligopolistic abuses. Many have attributed the current natural gas shortage to regulatory pricing policies and restrictions on the availability of public lands for oil and gas development. However, there are additional factors which may be constraining development and which could be changed in the future if proper action is taken.

The following list includes some of the more important factors which may be having an effect on the current development and production of non-associated gas.

Long-Term:

(1) Offshore leasing policies

- (a) size and frequency of sales
- (b) 5-year term of primary lease
- (c) bonus-bid system of leasing

(2) Tax policies

- (a) reduction of the depletion allowance from 27½ to 22 percent.

(3) Regulatory policies

- (a) environmental regulations; (1) required impact statements may cause procedural and decisional delays, (2) regulations may cause potential oil and gas producing leases to be eliminated from acreage available for lease.

(b) anti-trust regulations - to date anti-trust laws have had only limited impact on the development of natural gas resources.

(c) conservation regulations - conservation policies are principally the concern of state agencies except for Federal lands and in the Outer Continental Shelf where Federal agencies are responsible for the conservation of oil and gas resources and the safe operation of facilities. In general, these policies have not been detrimental to the production of gas. They have eliminated wasteful venting and flaring practices. However, these regulations can tend to delay the production of gas.

(d) economic regulation - this area is dominated by the Federal Power Commission in regulating the wellhead price and transportation of natural gas in interstate commerce. Regulatory delay has, in many cases, been a result of the need to protect the interests and rights of all parties concerned and to grant due process. The alternative, hasty decisions possibly followed by court reversal, could result, however, in even longer delays that would have a greater impact on investment decisions and gas development and production. It has also been widely argued that the prices permitted by the FPC have provided an inadequate economic incentive to the timely development of our natural gas resources.

Short-Term:

(1) Material shortages

(a) drilling rigs-both onshore and offshore
(b) offshore production platforms
(c) tubular goods; drill pipe, casing and tubing
(d) geophysical equipment

(2) Manpower shortages

(a) specialized technologists such as geologists, geophysicists, petroleum engineers and other specialists required for exploring, developing and producing natural gas.

Potential Policy Options

The policy options available to us generally fall into five broad categories: land use, regulatory, technical, financial and social response. Some of the more important of these options and their possible effects on the development and production of natural gas are covered in the following discussion. Most of these options have one thing in common -- they tend to increase the cost of gas to the consumer.

Land Use

(1) Offshore Leasing. The rate and size of offshore lease sales control the development of the OCS oil and gas resources. In the past, leasing in the OCS has been held at a relatively low level with only about 9 million acres being leased through the end of 1973. However, during 1973 the U.S. Department of Interior published a leasing schedule that proposed the offering of 3 million acres per year through 1978. More recently the Secretary of the Interior was directed to boost leasing in the OCS to 10 million acres in 1975. This should provide sufficient acreage for development but industry may find it difficult to adequately explore and develop this amount of acreage, at least in the near term, because of a shortage of both materials and manpower. Additionally, the current bonus-bid system, if continued, could also limit the capital available for development of the leases.

There are a number of alternative leasing systems which could be used instead of the present one but in general most of these are variations of the system currently in use. Some of these alternative systems are:

(a) A variable royalty bidding system. This would reduce initial capital investment but could cause early abandonment of fields and attract marginal or speculative operators.

(b) Retain the bonus bid system but reduce bonuses and require a higher fixed royalty rate. This could reduce initial capital investment but problems might be similar to those mentioned under (a).

(c) Employ a sliding royalty system. This could increase the likelihood of optimal recovery.

(d) Employ a staggered bonus system requiring payment of a portion of the bonus at various stages of development. The bidder would have the option of deciding whether to continue at each stage or to relinquish the lease. This could decrease the capital risk but could result in speculation and irresponsible operations.

(e) Employ a public drawing system which would specify a predetermined bonus for each lease. This could decrease capital requirements, offer greater potential for wider producer participation and provide increased funds for exploration and development.

(f) Employ a concession system. This is a non-competitive system, perhaps not politically feasible, which could result in a decrease in government income from OCS lands.

(2) Onshore Leasing. Onshore leasing options do not have the potential impact of offshore options. However, the following options could possibly improve the current leasing system:

(a) Provide a bonus payment or other incentive for rapid development of leases on federal property.

(b) Encourage passage of uniform, comprehensive land use legislation which would take into account the multiple uses of land, including the development of mineral resources in addition to their use for recreational and other non-energy producing activities.

(c) Institute a program to accelerate development of native lands in Alaska.

Regulatory

(1) Increase the price incentives for new gas at the wellhead. This would stimulate interest in investment in gas prone areas and increase available capital. It would also increase competition by attracting smaller operators and enhance the attractiveness of marginal prospects.

(2) Waive the Jones Act restrictions requiring use of American flag ships for transportation of LNG from Alaska to ports in the lower 48 states. This would lower transportation costs making the development of Alaskan potential gas supplies more feasible. However, it could have a detrimental effect upon the American shipbuilding industry and our balance of payments.

(3) Establish a federal exploration and development company. This organization's operations could be limited to public lands or it could compete in all areas. This could result in a more rapid and controlled development of our natural resources, especially in areas like the Atlantic offshore. Negative features would be the government's intervention in the free enterprise system, the taking of an unfair advantage over private companies, and the possibility of the occurrence of bureaucratic mismanagement and inefficiencies.

(4) The U.S. could embargo all overseas shipments of drilling rigs and production equipment. This could have a significant effect on worldwide production but equipment in short supply could be used in the U.S. Negative features are interference with international trade and possible retaliatory tactics by other trading parties.

(5) Federal or state action could be taken to relax the environmental limitations which have precluded drilling on some state lands. This would provide more land for oil and gas development.

(6) An FPC policy of special incentives for new discovery wells, deeper drilled wells, or other special circumstances could be established which would encourage exploration and development through higher prices. Producers would have more incentive to drill deep wells and high risk wildcats.

Technical

(1) Provide funds for a greatly accelerated geophysical effort. This could utilize private firms under federal contract support or direct government involvement either on a contractual or direct employment basis. This could result in more rapid discovery of potential gas supplies by identifying promising areas for exploratory drilling.

(2) Accelerate the research program for development of deep water pipeline technology. The effect could be more rapid development of deep water offshore gas fields.

(3) Institute research programs to establish the feasibility of producing natural gas from geopressured zones, to recover natural gas dissolved in formation waters and to improve the economics of natural gas recovery from coal fields. All three of these potential sources have relatively large resource bases and the successful commercial development of any or all of these sources could have a significant impact on the gas supply situation.

(4) Expand the research effort and institute additional research efforts to develop both nuclear and non-nuclear techniques for fracturing tight natural gas formations. This could result in providing a major new source of gas supply. Negative features are environmental problems with radioactive materials, geological effects and the use of otherwise needed nuclear supplies.

(5) Increase the research and development funding for natural gas exploration and development methods. This could result in more rapid discovery of potential gas supplies.

Social

(1) Social response options that might prove helpful in the accelerated development of future gas supplies might be:

(a) Creation of a program of preferred student loans for the mineral science fields with particular emphasis on petroleum and natural gas engineering.
(b) Establishment of retraining programs for aerospace and other personnel in industries with low or declining employment capacities, to provide exploration, development and production technicians and student training in technological institutions devoted to the development of gas technology specialist.
(c) Set higher federal minimum wage standards for personnel working on the OCS and on federal onshore lands.
(d) Set up federally assisted programs for mineral resources development in impacted areas.
(e) Provide relocation subsidies or allowances for people with needed skills to move into the gas producing areas.
(f) Establish job security provisions for personnel employed in developing federal resources.

Of the options listed, the Natural Gas Task Force considers the following as being the most feasible and as offering the greatest potential for improved gas supply development:

(1) Increased price incentives to stimulate interest and investment in the development of the Nation's natural gas resources.

(2) Rapid opening of public lands, both on and offshore, to exploration and development and revision of the present leasing system to provide timely resource development consistent with the collection of appropriate economic rents based on actual operating and economic conditions encountered.

(3) Waiver of Jones Act provisions for LNG movements from Alaska to the lower 48 states.

Implementations of these options is essential to movement toward the production possibilities of the accelerated development scenario and would undoubtedly improve the Nation's gas supply posture. The Task Force does not believe, however, that the impact of their enactment can be sufficient to provide all of the gas needed to meet demand.

APPENDIX A

DETAILED TABLES FOR SPECIAL SOURCES AND REGIONS

Key

BAU	Business As Usual
ACC	Accelerated Development
Low	Low activity level
Medium	Medium activity level
High	High activity level
NA	Non-associated gas
AD	Associated-dissolved gas
--	Not Available or Does Not Apply

Regions identified by NPC region.

SCENARIO : BAU
ACTIVITY LEVEL: Low
SPECIAL SOURCE: NA
REGION : 1N

YEAR	1974	1977	1980	1985	1988
Production *	.0	.0	.094	.160	.184
Minimum Acceptable Price **	--	--	.42	.42	.42
Cost Components:					
Operating Cost	--	--	.165	.165	.165
Leasing Cost	--	--	.009	.009	.009
Capital Investment	--	--	.108	.108	.108
Profit	--	--	.138	.138	.138

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: BAU, ACTIVITY LEVEL: LOW, SPECIAL SOURCE: NA, REGION: 1N

Year	Cumulative *	Current
1974	--	--
1977	73.8	30.0
1980	163.8	30.0
1985	291.3	22.5
1988	373.8	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA

SCENARIO : BAU

ACTIVITY LEVEL : Low

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	.140	.160	.184
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	31.33	32.79	25.50	17.49
Oil Country tubular #	0.77	0.81	0.63	0.43
Rig years	2.70	2.82	2.19	1.50
Rig man-years	79.45	83.15	64.67	44.35
New rigs	2.00	1.00	1.00	0.00
Seismic instruments	8.70	9.71	7.08	4.86
Steel #	1.73	1.40	1.17	.54
Heavy structural shapes #	0.50	0.25	0.25	.00

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA

SCENARIO : BAU

ACTIVITY LEVEL : Low

	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	.140	.160	.184
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	128.51	218.74	251.55
Managers...........	0.0	0.0	68.93	117.33	134.93
Clerical...........	0.0	0.0	93.53	159.19	183.07
Const. Craftsmen....	0.0	0.0	14.96	25.47	29.29
Foremen............	0.0	0.0	7.20	63.32	72.82
Other Craftsmen.....	0.0	0.0	72.67	123.70	142.25
Operatives.........	0.0	0.0	249.54	424.75	488.46
Service & Protective	0.0	0.0	8.87	15.09	17.36
Laborers...........	0.0	0.0	13.65	23.23	26.71
TOTAL..............	0.0	0.0	692.78	1179.20	1356.08

SCENARIO : BAU
ACTIVITY LEVEL: Medium
SPECIAL SOURCE: NA
REGION : 1N

YEAR	1974	1977	1980	1985	1988
Production *	.0	.0	.150	.320	.410
Minimum Acceptable Price **	--	--	.40	.40	.40
Cost Components:					
Operating Cost	--	--	.152	.152	.152
Leasing Cost	--	--	.009	.009	.009
Capital Investment	--	--	.112	.112	.112
Profit	--	--	.127	.127	.127

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)
SCENARIO: BAU, ACTIVITY LEVEL: MEDIUM, SPECIAL SOURCE: NA, REGION: 1N

Year	Cumulative *	Current
1974	--	--
1977	115.0	45.0
1980	272.5	60.0
1985	572.5	60.0
1988	812.5	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA

SCENARIO : BAU

ACTIVITY LEVEL : Medium

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	.150	.320	.410
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	29.60	40.53	42.81	44.63
Oil Country tubular #	1.17	1.60	1.69	1.76
Rig years	4.07	5.58	5.89	6.14
Rig man-years	120.10	164.45	173.69	181.08
New rigs	6.00	1.00	1.00	1.00
Seismic instruments	4.11	5.63	5.95	6.20
Steel #	3.72	2.39	2.51	2.60
Heavy structural shapes #	1.50	0.25	0.25	0.25

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA
SCENARIO : BAU
ACTIVITY LEVEL : Medium

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	.150	.320	.410
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	205.07	437.48	560.53
Managers............	0.0	0.0	110.00	234.66	300.66
Clerical............	0.0	0.0	149.24	318.38	407.93
Const. Craftsmen....	0.0	0.0	23.88	50.94	65.27
Foremen.............	0.0	0.0	59.37	126.65	162.27
Other Craftsmen.....	0.0	0.0	115.97	247.40	316.98
Operatives..........	0.0	0.0	398.20	849.50	1088.42
Service & Protective	0.0	0.0	14.15	30.19	38.68
Laborers............	0.0	0.0	21.78	46.46	59.53
TOTAL	0.0	0.0	1105.50	2358.40	3021.70

SCENARIO : BAU
ACTIVITY LEVEL: High
SPECIAL SOURCE: NA
REGION : 1N

YEAR	1974	1977	1980	1985	1988
Production *	.0	.0	.180	.415	.540
Minimum Acceptable Price **	--	--	.43	.43	.43
Cost Components:					
Operating Cost	--	--	.162	.162	.162
Leasing Cost	--	--	.010	.010	.010
Capital Investment	--	--	.122	.122	.122
Profit	--	--	.136	.136	.136

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: BAU, ACTIVITY LEVEL: HIGH, SPECIAL SOURCE: NA, REGION: 1N

Year	Cumulative *	Current
1974	--	--
1977	156.3	52.5
1980	351.3	82.5
1985	793.8	90.0
1988	1153.8	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA

SCENARIO : BAU

ACTIVITY LEVEL : High

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	.180	.415	.540
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	44.93	74.69	86.22	88.65
Oil Country tubular #	1.33	2.21	2.55	2.62
Rig years	4.64	7.71	8.90	9.15
Rig man-years	136.73	227.27	262.38	269.77
New rigs	6.00	3.00	1.00	1.00
Seismic instruments	6.24	10.37	11.98	12.31
Steel #	3.93	3.91	3.59	3.69
Heavy structural shapes #	1.50	0.75	0.25	0.25

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA
SCENARIO : BAU
ACTIVITY LEVEL : High

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	.180	.415	.540
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	246.08	567.36	738.25
Managers...........	0.0	0.0	132.00	304.33	395.99
Clerical...........	0.0	0.0	179.09	412.90	537.27
Const. Craftsmen....	0.0	0.0	28.65	66.06	85.96
Foremen............	0.0	0.0	71.24	164.24	213.72
Other Craftsmen.....	0.0	0.0	139.16	320.84	417.48
Operatives.........	0.0	0.0	477.84	1101.69	1433.52
Service & Protective	0.0	0.0	16.98	39.15	50.94
Laborers...........	0.0	0.0	26.13	60.25	78.40
TOTAL	0.0	0.0	1326.60	3058.55	3979.80

SCENARIO : ACC
ACTIVITY LEVEL: Low
SPECIAL SOURCE: NA
REGION : 1N

YEAR	1974	1977	1980	1985	1988
Production *	.0	.0	.225	.485	.615
Minimum Acceptable Price **	--	--	.81	.81	.81
Cost Components:					
Operating Cost	--	--	.305	.308	.308
Leasing Cost	--	--	.019	.019	.019
Capital Investment	--	--	.226	.226	.226
Profit	--	--	.257	.257	.257

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: LOW, SPECIAL SOURCE: NA, REGION: 1N

Year	Cumulative *	Current
1974	--	--
1977	246.3	90.0
1980	553.8	120.0
1985	1168.8	120.0
1988	1641.3	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA

SCENARIO : ACC

ACTIVITY LEVEL : Low

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	.225	.485	.615
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	41.40	58.29	64.25	60.61
Oil country tubular #	2.24	3.16	3.48	3.28
Rig years	7.83	11.03	12.16	11.47
Rig man-years	230.97	325.20	358.46	338.13
New rigs	9.00	2.00	1.00	0.0
Seismic instruments	5.75	8.10	8.92	8.42
Steel #	6.21	4.74	4.77	4.15
Heavy structural shapes #	2.25	0.50	0.25	0.0

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA
SCENARIO : ACC
ACTIVITY LEVEL : Low

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	.225	.485	.615
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	205.07	437.48	560.53
Managers...........	0.0	0.0	110.00	234.66	300.66
Clerical...........	0.0	0.0	149.24	318.38	407.93
Const. Craftsmen....	0.0	0.0	23.88	50.94	65.27
Foremen............	0.0	0.0	59.37	126.65	162.27
Other Craftsmen.....	0.0	0.0	115.97	247.40	316.98
Operatives.........	0.0	0.0	398.20	849.50	1088.42
Service & Protective	0.0	0.0	14.15	30.19	38.68
Laborers...........	0.0	0.0	21.78	46.46	59.53
TOTAL	0.0	0.0	1105.50	2358.40	3021.70

SCENARIO : ACC
ACTIVITY LEVEL: Medium
SPECIAL SOURCE: NA
REGION : 1N

YEAR	1974	1977	1980	1985	1988
Production *	.0	.0	.270	.630	.814
Minimum Acceptable Price **	--	--	.53	.53	.53
Cost Components:					
Operating Cost	--	--	.199	.199	.199
Leasing Cost	--	--	.013	.013	.013
Capital Investment	--	--	.151	.151	.151
Profit	--	--	.167	.167	.167

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: MEDIUM, SPECIAL SOURCE: NA, REGION: 1N

Year	Cumulative *	Current
1974	--	--
1977	293.1	105.0
1980	675.6	150.0
1985	1493.1	165.0
1988	2153.1	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA

SCENARIO : ACC

ACTIVITY LEVEL : Medium

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	.270	.630	.814
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	44.93	68.92	80.45	80.45
Oil country tubular #	2.65	4.07	4.75	4.75
Rig years	9.28	14.23	16.61	16.61
Rig man-years	273.46	419.43	489.65	489.65
New rigs	11.00	3.00	1.00	1.00
Seismic instruments	6.24	9.57	11.17	11.17
Steel #	7.48	6.27	6.38	6.38
Heavy structural shapes #	2.75	0.75	0.25	0.25

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA
SCENARIO : ACC
ACTIVITY LEVEL : Medium

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	270	.630	.814
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	369.13	861.29	1112.85
Managers...........	0.0	0.0	197.99	461.99	596.92
Clerical...........	0.0	0.0	268.64	626.82	809.89
Const. Craftsmen....	0.0	0.0	42.98	100.29	129.58
Foremen............	0.0	0.0	106.86	249.33	322.16
Other Craftsmen.....	0.0	0.0	208.74	487.06	629.31
Operatives.........	0.0	0.0	716.76	1672.44	2160.90
Service & Protective	0.0	0.0	25.47	59.43	76.79
Laborers...........	0.0	0.0	39.20	91.47	118.18
TOTAL	0.0	0.0	1989.90	4643.10	5999.18

SCENARIO : ACC
ACTIVITY LEVEL: High
SPECIAL SOURCE: NA
REGION : 1N

YEAR	1974	1977	1980	1985	1988
Production *	.0	.0	.295	.690	.895
Minimum Acceptable Price **	--	--	.53	.53	.53
Cost Components:					
Operating Cost	--	--	.201	.201	.201
Leasing Cost	--	--	.012	.012	.012
Capital Investment	--	--	.150	.150	.150
Profit	--	--	.167	.167	.167

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: HIGH, SPECIAL SOURCE: NA, REGION: 1N

Year	Cumulative *	Current
1974	--	--
1977	316.3	112.5
1980	728.8	165.0
1985	1628.8	187.5
1988	2356.3	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA

SCENARIO : ACC

ACTIVITY LEVEL : High

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	.295	.690	.895
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	49.49	75.90	88.35	88.35
Oil country tubular #	2.92	4.48	5.22	5.22
Rig years	10.22	15.67	18.24	18.24
Rig man-years	301.18	461.93	537.69	537.69
New rigs	12.00	4.00	1.00	1.00
Seismic instruments	6.87	10.54	12.27	12.27
Steel #	8.80	7.17	6.97	6.97
Heavy structural shapes #	3.00	1.00	0.25	0.25

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1N/NA
SCENARIO : ACC
ACTIVITY LEVEL : High

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	.295	.690	.895
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	403.30	943.32	1223.59
Managers............	0.0	0.0	216.33	505.99	656.32
Clerical............	0.0	0.0	293.51	686.51	890.48
Const. Craftsmen....	0.0	0.0	46.96	109.84	142.48
Foremen.............	0.0	0.0	116.75	273.08	354.21
Other Craftsmen.....	0.0	0.0	228.07	533.45	691.94
Operatives..........	0.0	0.0	783.13	1831.72	2375.93
Service & Protective	0.0	0.0	27.83	65.09	84.43
Laborers.............	0.0	0.0	42.83	100.18	129.94
TOTAL	0.0	0.0	2174.15	5085.30	6596.15

SCENARIO : BAU
ACTIVITY LEVEL: Low
SPECIAL SOURCE: NA
REGION : 1S

YEAR	1974	1977	1980	1985	1988
Production *	.120	.135	.155	.310	.352
Minimum Acceptable Price **	.30	.30	.30	.30	.30
Cost Components:					
Operating Cost	.114	.114	.114	.114	.114
Leasing Cost	.030	.030	.030	.030	.030
Capital Investment	.069	.069	.069	.069	.069
Profit	.087	.087	.087	.087	.087

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: BAU, ACTIVITY LEVEL: LOW, SPECIAL SOURCE: NA, REGION: 1S

Year	Cumulative *	Current
1974	--	--
1977	225.6	11.5
1980	335.2	46.2
1985	542.9	34.6
1988	658.3	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA

SCENARIO : BAU

ACTIVITY LEVEL : Low

	1977	1980	1985	1988
PRODUCTION (Tcf)	.135	.155	.310	.352
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	7.72	30.43	23.57	15.86
Oil country tubular #	0.32	1.27	0.99	0.66
Rig years	1.13	4.45	3.45	2.32
Rig man-years	33.26	131.19	101.62	68.37
New rigs	1.00	1.00	1.00	0.0
Seismic instruments	1.07	4.23	3.27	2.20
Steel #	11.78	12.98	12.62	0.84
Heavy structural shapes #	1.05	1.05	1.05	0.0

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA
SCENARIO : BAU
ACTIVITY LEVEL : Low

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	.120	.135	.155	.310	.352
MANPOWER (Man-hours)					
Professionals.......	164.06	184.56	211.91	423.81	481.23
Managers............	88.00	99.00	113.66	227.33	258.13
Clerical............	119.39	134.32	154.22	308.43	350.22
Const. Craftsmen....	19.10	21.49	24.67	49.35	56.04
Foremen.............	47.49	53.43	61.34	122.69	139.31
Other Craftsmen.....	92.77	104.37	119.83	239.66	272.14
Operatives..........	318.56	358.38	411.47	822.95	934.44
Service & Protective	11.32	12.74	14.62	29.24	33.21
Laborers............	17.42	19.60	22.50	45.01	51.11
TOTAL	884.40	994.95	1142.35	2284.70	2594.24

SCENARIO : BAU
ACTIVITY LEVEL: Medium
SPECIAL SOURCE: NA
REGION : 1S

YEAR	1974	1977	1980	1985	1988
Production *	.120	.150	.225	.470	.630
Minimum Acceptable Price **	.47	.47	.47	.47	.47
Cost Components:					
Operating Cost	.177	.177	.177	.177	.177
Leasing Cost	.046	.046	.046	.046	.046
Capital Investment	.106	.106	.106	.106	.106
Profit	.141	.141	.141	.141	.141

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: BAU, ACTIVITY LEVEL: MEDIUM, SPECIAL SOURCE: NA, REGION: 1S

Year	Cumulative *	Current
1974	--	--
1977	546.3	17.3
1980	725.2	86.6
1985	1215.7	115.4
1988	1700.3	0.0

---

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S /NA

SCENARIO : BAU

ACTIVITY LEVEL : Medium

	1977	1980	1985	1988
PRODUCTION (Tcf)	.150	.225	.470	.630
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	11.14	57.43	78.86	87.86
Oil country tubular #	0.47	2.40	3.30	3.68
Rig years	1.63	8.40	11.53	12.85
Rig man-years	48.04	247.59	339.98	378.78
New rigs	1.00	2.00	1.00	1.00
Seismic instruments	1.55	7.98	10.95	12.20
Steel #	11.96	25.79	15.55	16.02
Heavy structural shapes #	1.05	2.10	1.05	1.05

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA
SCENARIO : BAU
ACTIVITY LEVEL : Medium

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	.120	.150	.225	.470	.630
MANPOWER (Man-hours)					
Professionals.......	164.06	205.07	444.32	642.55	861.29
Managers............	88.00	110.00	238.33	344.66	461.99
Clerical............	119.39	149.24	323.36	467.63	626.82
Const. Craftsmen....	19.10	23.88	51.74	74.82	100.29
Foremen.............	47.49	59.37	128.62	186.01	249.33
Other Craftsmen.....	92.77	115.97	251.26	363.36	487.06
Operatives..........	318.56	398.20	862.77	1247.70	1672.44
Service & Protective	11.32	14.15	30.66	44.34	59.43
Laborers............	17.42	21.78	47.19	68.24	91.47
TOTAL	884.40	1105.50	2395.25	3463.90	4643.10

SCENARIO : BAU
ACTIVITY LEVEL: High
SPECIAL SOURCE: NA
REGION : 1S

YEAR	1974	1977	1980	1985	1988
Production *	.120	.150	.225	.560	.792
Minimum Acceptable Price **	.56	.56	.56	.56	.56
Cost Components:	.213	.213	.213	.213	.213
Operating Cost					
Leasing Cost	.052	.052	.052	.052	.052
Capital Investment	.120	.120	.120	.120	.120
Profit	.175	.175	.175	.175	.175

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: BAU, ACTIVITY LEVEL: HIGH, SPECIAL SOURCE: NA, REGION: 1S

Year	Cumulative *	Current
1974	--	--
1977	724.6	17.3
1980	943.8	115.4
1985	1607.4	155.8
1988	2265.2	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA

SCENARIO : BAU

ACTIVITY LEVEL : High

	1977	1980	1985	1988
PRODUCTION (Tcf)	.150	.225	.560	.792
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	7.29	49.88	69.50	78.15
Oil country tubular #	.47	3.19	4.45	5.00
Rig years	1.63	11.16	15.54	17.49
Rig man-years	48.04	328.89	458.23	515.51
New rigs	1.00	3.00	1.00	1.00
Seismic instruments	1.01	6.93	9.65	10.86
Steel #	11.96	38.16	17.00	17.70
Heavy structural shapes #	1.05	3.15	1.05	1.05

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA
SCENARIO : BAU
ACTIVITY LEVEL : High

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	.120	.150	.225	.560	792
MANPOWER (Man-hours)					
Professionals.......	164.06	205.07	307.61	765.59	1082.77
Managers............	88.00	110.00	165.00	410.66	580.79
Clerical............	119.39	149.24	223.86	557.17	788.00
Const. Craftsmen....	19.10	23.88	35.82	89.15	126.08
Foremen.............	47.49	59.37	89.05	221.63	313.45
Other Craftsmen.....	92.77	115.97	173.95	432.94	612.31
Operatives..........	318.56	398.20	597.30	1486.62	2102.00
Service & Protective	11.32	14.15	21.23	52.83	74.71
Laborers............	17.42	21.78	32.67	81.31	114.99
TOTAL	884.40	1105.50	1658.25	4127.20	5837.04

SCENARIO : ACC
ACTIVITY LEVEL: Low
SPECIAL SOURCE: NA
REGION : 1S

YEAR	1974	1977	1980	1985	1988
Production *	.120	.200	.430	.800	1.050
Minimum Acceptable Price *	.47	.47	.47	.47	.47
Cost Components:					
Operating Cost	.180	.180	.180	.180	.180
Leasing Cost	.043	.043	.043	.043	.043
Capital Investment	.099	.099	.099	.099	.099
Profit	.148	.148	.148	.148	.148

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: LOW, SPECIAL SOURCE: NA, REGION: 1S

Year	Cumulative *	Current
1974	--	--
1977	881.4	86.5
1980	1152.5	98.1
1985	1856.4	161.6
1988	2554.6	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA

SCENARIO : ACC

ACTIVITY LEVEL : Low

	1977	1980	1985	1988
PRODUCTION (Tcf)	.200	.430	.800	1.050
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	36.99	42.32	72.30	86.04
Oil country tubular #	2.37	2.71	4.63	5.51
Rig years	8.27	9.46	16.17	19.24
Rig man-years	243.90	279.01	476.71	567.25
New rigs	1.00	2.00	0.0	2.00
Seismic instruments	5.14	5.88	10.04	11.95
Steel #	14.37	26.17	5.85	29.71
Heavy structural shapes #	1.05	2.10	0.0	2.10

* Gas production figures are given in Bcf per year.

Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA
SCENARIO : ACC
ACTIVITY LEVEL : Low

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	.120	.200	.430	.800	1.050
MANPOWER (Man-hours)					
Professionals.......	164.06	273.43	587.87	1093.71	1435.49
Managers............	88.00	146.66	315.33	586.65	769.98
Clerical............	119.39	198.99	427.83	795.96	1044.70
Const. Craftsmen....	19.10	31.84	68.45	127.35	167.15
Foremen.............	47.49	79.15	170.18	316.61	415.56
Other Craftsmen.....	92.77	154.62	332.44	618.49	811.77
Operatives..........	318.56	530.93	1141.51	2123.74	2787.41
Service & Protective	11.32	18.87	40.56	75.47	99.05
Laborers............	17.42	29.04	62.43	116.15	152.45
TOTAL	884.40	1474.00	3169.10	5896.00	7738.50

SCENARIO : ACC
ACTIVITY LEVEL: Medium
SPECIAL SOURCE: NA
REGION : 1S

YEAR	1974	1977	1980	1985	1988
Production *	.120	.225	.500	1.000	1.360
Minimum Acceptable Price **	.49	.49	.49	.49	.49
Cost Components:					
Operating Cost	.329	.329	.329	.329	.329
Leasing Cost	.044	.044	.044	.044	.044
Capital Investment	.103	.103	.103	.103	.103
Profit	.155	.155	.155	.155	.155

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: MEDIUM, SPECIAL SOURCE: NA, REGION: 1S

Year	Cumulative *	Current
1974	--	--
1977	1135.4	132.7
1980	1475.9	132.7
1985	2422.1	219.3
1988	3356.9	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA

SCENARIO : ACC

ACTIVITYLEVEL : Medium

	1977	1980	1985	1988
PRODUCTION (Tcf)	.225	.500	1.000	1.360
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	44.28	57.45	98.09	112.10
Oil country tubular #	2.83	3.68	6.28	7.18
Rig years	9.90	12.85	21.94	25.07
Rig man-years	291.94	378.78	646.70	739.09
New rigs	2.00	3.00	0.0	1.00
Seismic instruments	6.15	7.98	13.62	15.57
Steel #	26.33	38.77	7.94	20.45
Heavy structural shapes #	2.10	3.15	0.0	1.05

* Gas production figures are given in Bcf per year.

Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA
SCENARIO : ACC
ACTIVITY LEVEL : Medium

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	.120	.225	.500	1.000	1.360
MANPOWER (Man-hours)					
Professionals.......	164.06	307.61	683.57	1367.13	1859.30
Managers...........	88.00	165.00	366.66	733.31	997.31
Clerical...........	119.39	223.86	497.47	994.95	1353.13
Const. Craftsmen....	19.10	35.82	79.60	159.19	216.50
Foremen............	47.49	89.05	197.88	395.77	538.25
Other Craftsmen.....	92.77	173.95	386.56	773.11	1051.43
Operatives.........	318.56	597.30	1327.34	2654.67	3610.36
Service & Protective	11.32	21.23	47.17	94.34	128.30
Laborers...........	17.42	32.67	72.59	145.19	197.46
TOTAL	884.40	1658.25	3685.00	7370.00	10023.20

SCENARIO : ACC
ACTIVITY LEVEL: High
SPECIAL SOURCE: NA
REGION : 1S

YEAR	1974	1977	1980	1985	1988
Production *	.120	.275	.515	1.125	1.530
Minimum Acceptable Price **	.51	.51	.51	.51	.51
Cost Components:					
Operating Cost	.195	.195	.195	.195	.195
Leasing Cost	.046	.046	.046	.046	.046
Capital Investment	.108	.108	.108	.108	.108
Profit	.161	.161	.161	.161	.161

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Total Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: HIGH, SPECIAL SOURCE: NA, REGION: 1S

Year	Cumulative *	Current
1974	--	--
1977	1268.7	115.4
1980	1638.0	144.3
1985	2711.2	295.6
1988	3814.7	0.0

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA

SCENARIO : ACC

ACTIVITY LEVEL : High

	1977	1980	1985	1988
PRODUCTION (Tcf)	.275	.515	1.125	1.530
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	49.32	63.06	116.02	129.99
Oil country tubular #	3.16	4.04	7.43	8.00
Rig years	11.03	14.10	25.95	27.95
Rig man-years	325.20	415.74	764.96	824.08
New rigs	3.00	4.00	0.00	2.00
Seismic instruments	6.85	8.76	16.11	17.36
Steel #	38.12	50.60	9.39	32.86
Heavy structural shapes #	3.15	4.20	0.00	2.10

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 1S/NA
SCENARIO : ACC
ACTIVITY LEVEL : High

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	.120	.275	.515	1.125	1.530
MANPOWER (Man-hours)					
Professionals.......	164.06	375.96	683.57	1503.85	2006.95
Managers.	88.00	201.66	366.66	806.65	1076.51
Clerical...........	119.39	273.61	497.97	1094.44	1460.59
Const. Craftsmen....	19.10	43.78	79.60	175.11	233.69
Foremen............	47.49	108.84	197.88	435.35	580.99
Other Craftsmen.....	92.77	212.61	386.56	850.42	1134.93
Operatives..........	318.56	730.03	1321.34	2920.14	3897.06
Service & Protective	11.32	25.94	47.17	103.77	138.49
Laborers...........	17.42	39.93	72.59	159.71	213.14
TOTAL	884.40	2026.75	3685.00	8107.00	10819.16

SCENARIO : BAU
ACTIVITY LEVEL: High
SPECIAL SOURCE: TIGHT GAS
REGION : 3

YEAR	1974	1977	1980	1985	1988
Production *	0.0	0.0	0.1	0.2	0.3
Minimum Acceptable Price **	--	--	0.43	0.50	0.57
Cost Components:					
Operating Cost	--	--	--	--	--
Leasing Cost	--	--	--	--	--
Capital Investment	--	--	--	--	--
Profit	--	--	--	--	--

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 dubic feet.

Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: BAU, ACTIVITY LEVEL: HIGH, SPECIAL SOURCE: TIGHT GAS, REGION: 3

Year	Cumulative *	Current
1974	0	14
1977	42	28
1980	126	44
1985	336	44
1988	546	44

* Cumulative from January 1, 1975 exclusive of current year..

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 3/TIGHT GAS

SCENARIO : BAU

ACTIVITY LEVEL : High

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.1	0.2	0.3
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	11.82	17.73	17.73	17.73
Oil country tubular #	1.30	1.95	1.95	1.95
Rig years	1.18	1.76	1.76	1.76
Rig man-years	34.68	52.02	52.02	52.02
New rigs	2.00	1.00	1.00	1.00
Seismic instruments	1.23	1.85	1.85	1.85
Steel #	3.58	4.77	4.77	4.77
Heavy structural shapes #	0.33	0.16	0.16	0.16

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 3/TIGHT GAS
SCENARIO : BAU
ACTIVITY LEVEL : High

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	0.1	0.2	0.3
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	136.71	273.43	307.61
Managers...........	0.0	0.0	73.33	146.66	165.00
Clerical...........	0.0	0.0	99.49	198.99	223.86
Const. Craftsmen....	0.0	0.0	15.92	31.84	35.82
Foremen............	0.0	0.0	39.58	79.15	89.05
Other Craftsmen.....	0.0	0.0	77.31	154.62	173.95
Operatives.........	0.0	0.0	265.47	530.93	597.30
Service & Protective	0.0	0.0	9.43	18.87	21.23
Laborers...........	0.0	0.0	14.52	29.04	32.67
TOTAL	0.0	0.0	737.00	1474.00	1658.25

SCENARIO : ACC
ACTIVITY LEVEL: Low
SPECIAL SOURCE: TIGHT GAS
REGION : 3

YEAR	1974	1977	1980	1985	1988
Production *	0.0	0.0	0.1	0.3	0.5
Minimum Acceptable Price **	--	--	0.57	0.67	0.73
Cost Components:					
Operating Cost	--	--	--	--	--
Leasing Cost	--	--	--	--	--
Capital Investment	--	--	--	--	--
Profit	--	--	--	--	--

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: LOW, SPECIAL SOURCE: TIGHT GAS, REGION: 3

Year	Cumulative *	Current
1974	0	26
1977	80	54
1980	351	105
1985	882	105
1988	1407	105

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 3/TIGHT GAS

SCENARIO : ACC

ACTIVITY LEVEL : Low

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.1	0.3	0.5
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	23.64	47.28	47.28	47.28
Oil country tubular #	2.60	5.20	5.20	5.20
Rig years	2.35	4.71	4.71	4.71
Rig man-years	69.37	138.73	138.73	138.73
New rigs	3.00	1.00	1.00	1.00
Seismic instruments	2.46	4.93	4.93	4.93
Steel #	6.86	12.22	12.22	12.22
Heavy structural shapes				

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 3/TIGHT GAS
SCENARIO : ACC
ACTIVITY LEVEL : Low

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	0.1	0.3	0.5
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	273.43	410.14	615.21
Managers...........	0.0	0.0	146.66	219.99	329.99
Clerical...........	0.0	0.0	198.99	298.48	447.73
Const. Craftsmen....	0.0	0.0	31.84	47.76	71.64
Foremen............	0.0	0.0	79.15	118.73	178.10
Other Craftsmen.....	0.0	0.0	154.62	231.93	347.90
Operatives.........	0.0	0.0	530.93	796.40	1194.60
Service & Protective	0.0	0.0	18.87	28.30	42.45
Laborers...........	0.0	0.0	29.04	43.56	65.34
TOTAL	0.0	0.0	1474.00	2211.00	3316.50

SCENARIO : ACC
ACTIVITY LEVEL: Medium
SPECIAL SOURCE: Tight Gas
REGION : 3

YEAR	1974	1977	1980	1985	1988
Production *	0.0	0.0	0.2	0.3	0.5
Minimum Acceptable Price **	--	--	0.60	0.70	0.76
Cost Components:					
Operating Cost	--	--	--	--	--
Leasing Cost	--	--	--	--	--
Capital Investment	--	--	--	--	--
Profit	--	--	--	--	--

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: MEDIUM, SPECIAL SOURCE: TIGHT GAS, REGION 3

Year	Cumulative *	Current
1974	0	26
1977	80	54
1980	357	105
1985	882	105
1988	1407	105

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 3/TIGHT GAS

SCENARIO : ACC

ACTIVITY LEVEL : Medium

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.2	0.3	0.5
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	23.64	47.28	47.28	47.28
Oil country tubular #	2.60	5.20	5.20	5.20
Rig years	2.35	4.71	4.71	4.71
Rig man-years	69.37	138.73	138.73	138.73
New rigs	3.00	1.00	1.00	1.00
Seismic instruments	2.46	4.93	4.93	4.93
Steel #	6.86	12.22	12.22	12.22
Heavy structural shapes #	0.49	0.16	0.16	0.16

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 3/TIGHT GAS
SCENARIO : ACC
ACTIVITY LEVEL : Medium

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	0.2	0.3	0.5
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	273.43	410.14	615.21
Managers...........	0.0	0.0	146.66	219.99	329.99
Clerical...........	0.0	0.0	198.99	298.48	447.73
Const. Craftsmen....	0.0	0.0	31.84	47.76	71.64
Foremen............	0.0	0.0	79.15	118.73	178.10
Other Carftsmen.....	0.0	0.0	154.62	231.93	347.90
Operatives.........	0.0	0.0	530.93	796.40	1194.60
Service & Protective	0.0	0.0	18.87	28.30	42.45
Laborers...........	0.0	0.0	29.04	43.56	65.34
TOTAL	0.0	0.0	1474.00	2211.00	3316.50

SCENARIO : ACC
ACTIVITY LEVEL: High
SPECIAL SOURCE: TIGHT GAS
REGION : 3

YEAR	1974	1977	1980	1985	1988
Production *	0.0	0.2	0.8	1.5	1.7
Minimum Acceptable Price **	--	0.36	0.40	0.47	0.53
Cost Components:					
Operating Cost	--	--	--	--	--
Leasing Cost	--	--	--	--	--
Capital Investment	--	--	--	--	--
Profit	--	--	--	--	--

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: HIGH, SPECIAL SOURCE: TIGHT GAS, REGION: 3

Year	Cumulative *	Current
1974	0	26
1977	133	107
1980	715	210
1985	1765	210
1988	2815	210

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 3/TIGHT GAS

SCENARIO : ACC

ACTIVITY LEVEL : High

	1977	1980	1985	1988
PRODUCTION	0.2	0.8	1.5	1.7
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	47.28	94.56	94.56	94.56
Oil country tubular #	5.20	10.40	10.40	10.40
Rig years	4.71	9.41	9.41	9.41
Rig man-years	138.73	277.47	277.47	277.47
New rigs	5.00	2.00	1.00	1.00
Seismic instruments	4.93	9.85	9.85	9.85
Steel #	13.42	24.44	24.14	24.14
Heavy structural shapes #	0.82	0.33	0.16	0.16

* Gas production figures are given in Bcf per year.

Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 3/TIGHT GAS
SCENARIO : ACC
ACTIVITY LEVEL : High

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.2	0.8	1.5	1.7
MANPOWER (Man-hours)					
Professionals.......	0.0	273.43	1093.71	2050.97	2187.42
Managers...........	0.0	146.66	586.65	1099.97	1173.30
Clerical...........	0.0	198.99	795.96	1492.42	1591.92
Const. Craftsmen....	0.0	31.84	127.35	238.79	254.71
Foremen............	0.0	79.15	316.61	593.65	638.23
Other Craftsmen.....	0.0	154.62	618.49	1159.67	1236.98
Operatives.........	0.0	530.93	2123.74	3982.07	4247.48
Service & Protective	0.0	18.87	75.47	141.50	150.94
Laborers...........	0.0	29.04	116.15	217.78	232.80
TOTAL	0.0	1474.00	5986.00	11105.00	11792.00

SCENARIO : ACC
ACTIVITY LEVEL: Medium
SPECIAL SOURCE: TIGHT GAS
REGION : 4

YEAR	1974	1977	1980	1985	1988
Production *	0.0	0.0	0.1	0.3	0.3
Minimum Acceptable Price **	--	--	0.60	0.70	0.76
Cost Components:					
Operating Cost	--	--	--	--	--
Leasing Cost	--	--	--	--	--
Capital Investment	--	--	--	--	--
Profit	--	--	--	--	--

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: MEDIUM, SPECIAL SOURCE: TIGHT GAS, REGION 4

Year	Cumulative *	Current
1974	0	20
1977	49	29
1980	242	77
1985	627	77
1988	1012	77

* Cumulative from January 1, 1975 exclusive of current year.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 4/TIGHT GAS

SCENARIO : ACC

ACTIVITY LEVEL : Medium

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.1	0.3	0.3
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	11.66	31.09	31.09	31.09
Oil country tubular #	0.97	2.60	2.60	2.60
Rig years	0.88	2.35	2.35	2.35
Rig man-years	26.01	69.37	69.37	69.37
New rigs	1.00	1.00	1.00	1.00
Seismic instruments	1.21	3.24	3.24	3.24
Steel #	2.53	6.26	6.26	6.26
Heavy structural shapes #	0.16	0.16	0.16	0.16

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 4/TIGHT GAS
SCENARIO : ACC
ACTIVITY LEVEL : Medium

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	.01	.03	.03
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	136.71	410.14	410.14
Managers............	0.0	0.0	73.33	219.99	219.99
Clerical............	0.0	0.0	99.49	298.48	298.48
Const. Craftsmen....	0.0	0.0	15.92	47.76	47.76
Foremen.............	0.0	0.0	39.58	118.73	118.73
Other Craftsmen.....	0.0	0.0	77.31	231.93	231.93
Operatives..........	0.0	0.0	265.47	796.40	796.40
Service & Protective	0.0	0.0	9.43	28.30	28.30
Laborers............	0.0	0.0	14.52	43.56	43.56
TOTAL	0.0	0.0	737.00	2211.00	2211.00

SCENARIO : ACC
ACTIVITY LEVEL: High
SPECIAL SOURCE: TIGHT GAS
REGION : 4

YEAR	1974	1977	1980	1985	1988
Production *	0.0	0.0	0.3	0.5	0.6
Minimum Acceptable Price **	--	--	0.40	0.47	0.53
Cost Components:					
Operating Cost	--	--	--	--	--
Leasing Cost	--	--	--	--	--
Capital Investment	--	--	--	--	--
Profit	--	--	--	--	--

* Production is given in trillions of cubic feet.

** Price and costs are given in constant 1973 dollars per 1000 cubic feet.

MATERIALS REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 4/TIGHT GAS

SCENARIO : ACC

ACTIVITY LEVEL : High

	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.3	0.5	0.6
MATERIALS & SPECIAL RESOURCES				
Seismic crew months	23.32	62.18	62.18	62.18
Oil country tubular #	1.95	5.20	5.20	5.20
Rig years	1.76	4.71	4.71	4.71
Rig man-years	52.02	138.73	138.73	138.73
New rigs	2.00	1.00	1.00	1.00
Seismic instruments	2.43	6.48	6.48	6.48
Steel #	5.07	12.22	12.22	12.22
Heavy structural shapes #	0.33	0.16	0.16	0.16

* Gas production figures are given in Bcf per year.

\# Thousands of tons.

Capital Investment
(Millions of Constant 1973 Dollars)

SCENARIO: ACC, ACTIVITY LEVEL: HIGH

Year	Cumulative *	Current
1974	0	39
1977	97	58
1980	483	155
1985	1258	155
1988	2033	155

* Cumulative from January 1, 1975 exclusive of current year.

MANPOWER REQUIRED TO ATTAIN GAS PRODUCTION
LEVELS FOR SELECTED YEARS 1977-1988 *

REGION/RESOURCE: 4/TIGHT GAS
SCENARIO : ACC
ACTIVITY LEVEL : High

YEAR	1974	1977	1980	1985	1988
PRODUCTION (Tcf)	0.0	0.0	.03	.05	.06
MANPOWER (Man-hours)					
Professionals.......	0.0	0.0	410.14	683.57	751.92
Managers...........	0.0	0.0	219.99	366.66	403.32
Clerical...........	0.0	0.0	298.48	497.47	547.22
Const. Craftsmen....	0.0	0.0	47.76	79.60	87.56
Foremen............	0.0	0.0	118.73	197.88	217.67
Other Craftsmen.....	0.0	0.0	231.93	386.56	425.21
Operatives.........	0.0	0.0	796.40	1327.34	1460.07
Service & Protective	0.0	0.0	28.30	47.17	51.88
Laborers...........	0.0	0.0	43.56	72.59	79.85
TOTAL	0.0	0.0	2211.00	3685.00	4053.50

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